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ANALYSIS OF PETROLEUM SOURCE ROCKS OF THE BAKKEN FORMATION (DEVONIAN AND MISSISSIPPIAN) IN NORTH DAKOTA

by
Rick L. Webster

Bachelor of Science, University of North Dakota

A Thesis

Submitted to the Graduate Faculty

of the

University of North Dakota

in partial fulfillment of the requirements

for the degree of

Master of Science

Grand Forks, North Dakota

September

1982

This thesis submitted by Rick L. Webster in partial fulfillment of the requirements for the Degree of Master of Science from the University of North Dakota is hereby approved by the Faculty Advisory Committee under whom the work has been done.

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Date September 21, 1982

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Sunmark Exploration Company and ARCO Exploration Company are gratefully acknowledged for the donation of Bakken samples from wildcat wells they drilled in eastern North Dakota during the summer of 1981.

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ABSTRACT

The Bakken Formation of North Dakota consists of upper and lower, black, organic-rich shales separated by a calcareous siltstone middle member. The formation is a relatively thin unit (maximum thickness of 145 feet) with the lower shale attaining a maximum thickness of 50 feet and the upper shale a maximum thickness of 23 feet. The shales are hard, siliceous, pyritic, fissile, and noncalcareous. They contain abundant conodonts and tasmanites and have planar laminations accented by pyrite. The upper and lower shales were apparently deposited in an offshore, marine, anoxic environment where anoxic conditions may have been caused by silling of the basin or the establishment of upwelling currents. Organic matter depositied in the black shales was derived mostly from planktonic algae.

Organic geochemical analyses used to evaluate the Bakken shales as petroleum source rocks include organic carbon measurements, chromatographic analysis of organic extracts, pyrolysis, vitrinite reflectance, and visual kerogen typing. Organic carbon measurements revealed the Bakken shales to be very organic-rich (average of 11.33 weight percent of organic carbon) and visual kerogen typing revealed this organic matter to be predominantly an amorphous type which is inferred to be sapropelic. The onset of hydrocarbon generation was determined to occur at an average depth of 9,000 feet by interpreting plots of geochemical parameters with depth (e.g. ratios of hydrocarbon to non-hydrocarbon, saturated hydrocarbon to organic carbon, pyrolytic hydro-

carbon to organic carbon, and the pyrolysis production index). Hydrocarbon content and thermal kerogen breakdown increase greatly in the Bakken shales where they are buried greater than 9,000 feet. The effective source area of the Bakken, as determined by maps of the above geochemical parameters, lies mostly in McKenzie, Williams, Dunn, and Billings Counties. Oil generation was probably initiated in the Bakken about 80 million years ago (Late Cretaceous) at a temperature of about 100°C, with initial expulsion of oil from the Bakken probably occurring 70-80 million years ago (Late Cretaceous).

Vertical fracture systems, located primarily along the Nesson anticline, Antelope Oil Field, and the Billings nose, seem to be the most reasonable way for migration of oil to occur from the Bakken into adjacent rock units. Lateral migration of Bakken oil took place in porosity zones of the Madison Group predominantly to the north and northeast of the effective Bakken source area. The migration of oil from the Bakken has apparently taken place as continuous-phase (or bulk) oil migration. Primary oil migration may have affected the hydrocarbon data used in this study by increasing or deleting the indigenous hydrocarbon content of the Bakken shales.

INTRODUCTION

The black shales of the Bakken Formation in North Dakota have been cited as possible source rocks of petroleum (Murray, 1968; Dow, 1974), yet detailed stratigraphic and geochemical studies of these shales have not been made. The Bakken Formation provides a good opportunity to study changes in source rock maturation with depth in a single stratigraphic unit, as numerous samples of the formation in North Dakota are available from the North Dakota Geological Survey.

The purpose of this paper is to present the results of a study of the regional stratigraphy and organic geochemistry of the Bakken shales in North Dakota (Fig. 1) and, by these means, to evaluate the Bakken shales as possible petroleum source rocks.

The Bakken Formation in North Dakota is known only from the subsurface; thus, it was studied by the use of well cores, well cuttings, and well logs. A list of all the wells used in this study appears as Appendix A.

Regional and Stratigraphic Setting

The Williston basin is an intracratonic basin with the deepest basement located near Williston, North Dakota (Carlson and Anderson, 1965, p. 1833). All systems are represented in the rock record of the basin, with a sedimentary rock column more than 15,000 feet thick in the deepest part of the basin. Major structural features within the basin include the Nesson and Cedar Creek anticlines (Fig. 1).

Figure 2 shows the position of the Bakken Formation in the

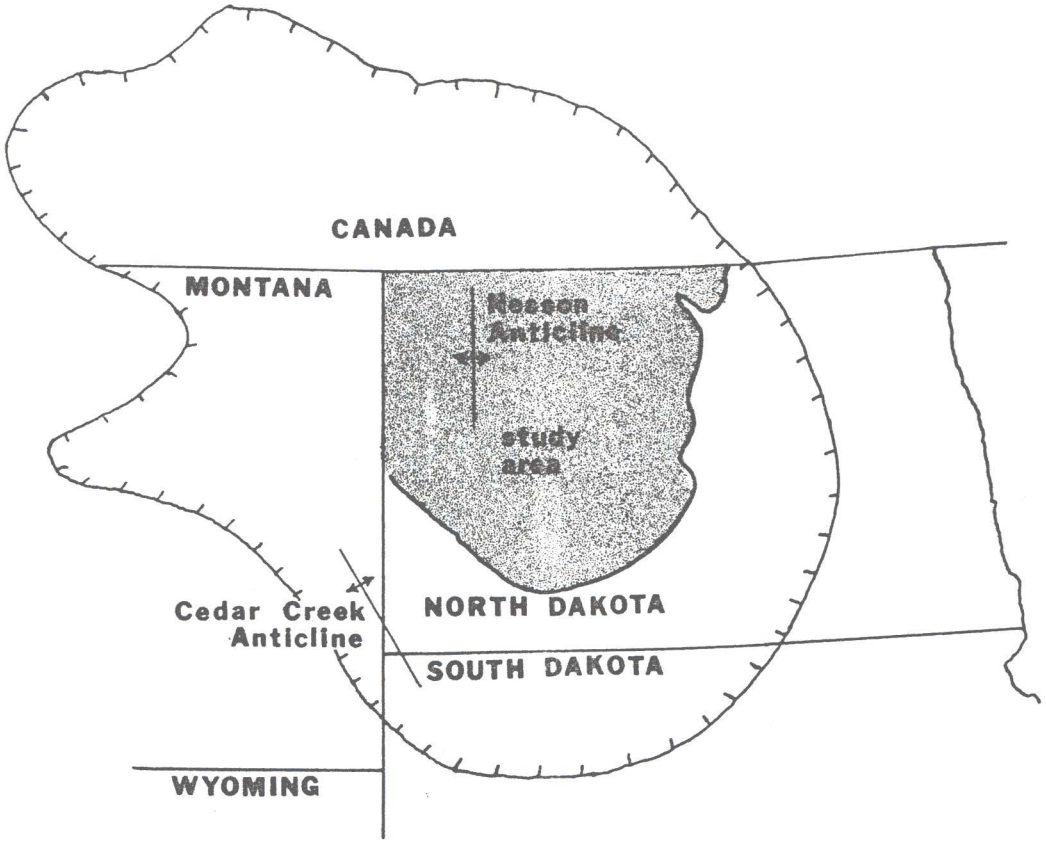


Fig. 1. Location of study area and major structural features of the Williston basin. The heavyline represents the approximate limit of the Bakken Formation in North Dakota and the hachured line represents the extent of the Williston basin.

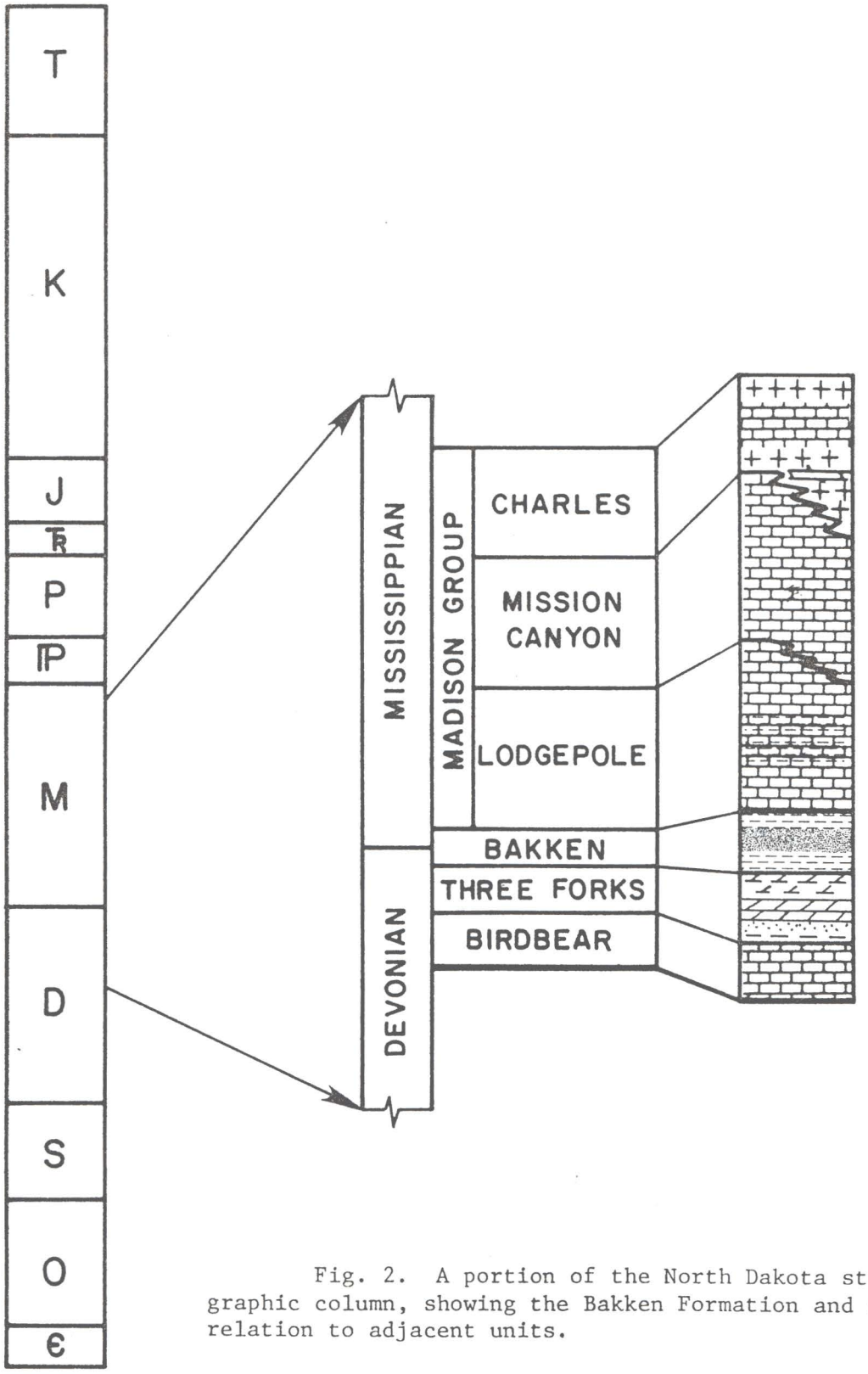


Fig. 2. A portion of the North Dakota stratigraphic column, showing the Bakken Formation and its relation to adjacent units.

North Dakota stratigraphic column and the relation of this formation to underlying and overlying units. Although the Bakken has been considered to be earliest Mississippian in age by several workers in the Williston basin (e.g. Nordquist, 1953; Kume, 1963) the exact age of the formation has not yet been thoroughly documented, and it may be that the boundary of the Mississippian-Devonian System lies within the formation (Sandberg and Hammond, 1958; Bluemle et al., 1980).

The Bakken is easily divided into three members and these are used informally here: the upper shale member, the middle (siltstone) member, and the lower shale member. These members will be discussed further in later sections of this report.

Various black shale units around the craton of Late Devonian to Early Mississippian age are near equivalents to the Bakken of the Williston basin. They are known variously as the Exshaw in Canada and the northern Rocky Mountains, the Pilot in the Cordilleran area, the "Lower Mississippian Shale" in the Permian basin, the Woodford Shale in the eastern Midcontinent/southern Appalachian basin, the Antrim Shale in the Michigan basin, and the New Albany Group in the northern Appalachian basin (Meissner, 1978, p. 208).

Methods of Study

Well logs kept at the North Dakota Geological Survey were used to obtain data for the maps and cross sections of the Bakken. Ten cores of the formation were examined and described (Appendix C). These cores were examined by means of a low-power, binocular microscope. About 50 thin sections were used to aid in determining lithology of the cores. Lithology, color (according to Goddard et al., 1948), bedding features, fossils, and possible fracturing were recorded for

each of the cores described.

Samples of the Bakken shales for organic geochemical analyses were obtained from cores and well cuttings. These samples were then sent to the Conoco Exploration Research Laboratory in Ponca City, Oklahoma, and to the U.S. Geological Survey Laboratory in Denver, Colorado, where organic geochemical analyses were run. The author compiled and interpreted the raw data from these analyses to draw conclusions about the source rock properties of the Bakken shales. Sampling methods and the details of the organic geochemical analyses are discussed in the source rock evaluation section.

Previous Work

Nordquist (1953) was the first to publish on the stratigraphy of the Bakken Formation in North Dakota and Montana. He formally defined the formation and discussed its extent, lithology, thickness, and stratigraphic relationships in these areas. Kume (1963) added further stratigraphic information on the Bakken in North Dakota and compared the Bakken to the Englewood Formation in South Dakota in an attempt to understand the relationship between the two. Other authors who have done stratigraphic work on the Bakken in North Dakota include Sandberg and Hammond (1958), Christopher (1962), and Ballard (1963). Numerous authors (e.g. Reasoner and Hunt, 1954; Fuller, 1956; MacDonald, 1956; Stanton, 1956; Raasch, 1956; McCabe, 1959) have done work on the Bakken, or its immediate correlatives, in Canada.

Murray (1968), in his study of fracturing in the Antelope Oil Field of North Dakota, noted the distinctive behavior of the Bakken shale members on gamma ray, sonic, neutron, and resistivity logs and was the first to relate their petrophysical properties to possible

petroleum source rock properties and overpressured reservoir properties. Meissner (1978), in a paper on the petroleum geology of the Bakken, studied well log characteristics, fracturing, and overpressuring of the formation. He speculated on the source rock properties and maturity of the Bakken shales as seen in changes in their petrophysical properties such as resistivity and sonic travel time. Meissner suggested that oil generation occurred in the Bakken shales over the depth range of 6,200-8,200 feet, and mapped the area of mature Bakken as derived from changes in well log properties. Webster (1980) studied radioactivity of the Bakken shales and attempted to map gamma ray intensity in these shales.

Several papers have been published that include geochemistry of the Bakken Formation. Williams (1974) analyzed the composition of organic matter soluble in organic solvents (extractable organic matter) of the Bakken shales and matched the composition of these Bakken extracts to the composition of oils in reservoirs of the overlying Madison Group. Dow (1974) mapped organic carbon values of the Bakken shales and elaborated on the significance for oil exploration of the data gathered by Williams, suggesting probable migration paths for oil originating in the Bakken. Dow also speculated on the oil generation depth of the Bakken shales (7,000 feet burial depth) and the amount of oil expelled by the shales. Thode (1981) studied sulfur isotopes from extracts of the Bakken shales and from oils in Mississippian reservoirs of the Williston basin and concluded that there was a reasonably close match between the two.

STRATIGRAPHY

Type Section

The type section of the Bakken Formation as formally defined by Nordquist (1953) occurs in the Amerada Petroleum Corporation H.O. Bakken No. 1 well located in SW¼, NW¼, sec. 12, T. 157 N., R. 95 W., Williams County, North Dakota, between the depths of 9615 and 9720 feet (Fig. 3). The lithologies of the three informal members were also described by Kume (1963) from well cuttings. He found both shales to be dark gray (N3), slightly calcareous, fissile, and pyritic. The middle member, as described by Kume, is brownish gray (5YR 4/1) to light gray (N7), very fine grained, calcareous sandstone, with rounded to subrounded quartz grains; and approximately 15 percent of the sample consisted of yellow gray (5Y 7/2) anhydrite.

Well Log Characteristics

The Bakken displays characteristic log responses that are unique in the Paleozoic rock section of the Williston basin and is widely used as a "marker" unit in the basin. The shales of the formation always display very high gamma ray readings (greater than 200 API) which are almost always off the log scale and not quantifiable. They also display high interval transit times (80-120 microsec./ft.) on the sonic log. High resistivity readings (greater than 100 ohm-meters) are seen from the shales in the deep portions of the basin (greater than 7,000-8,000 ft. deep) and low resistivity (less than 10 ohm-meters) is

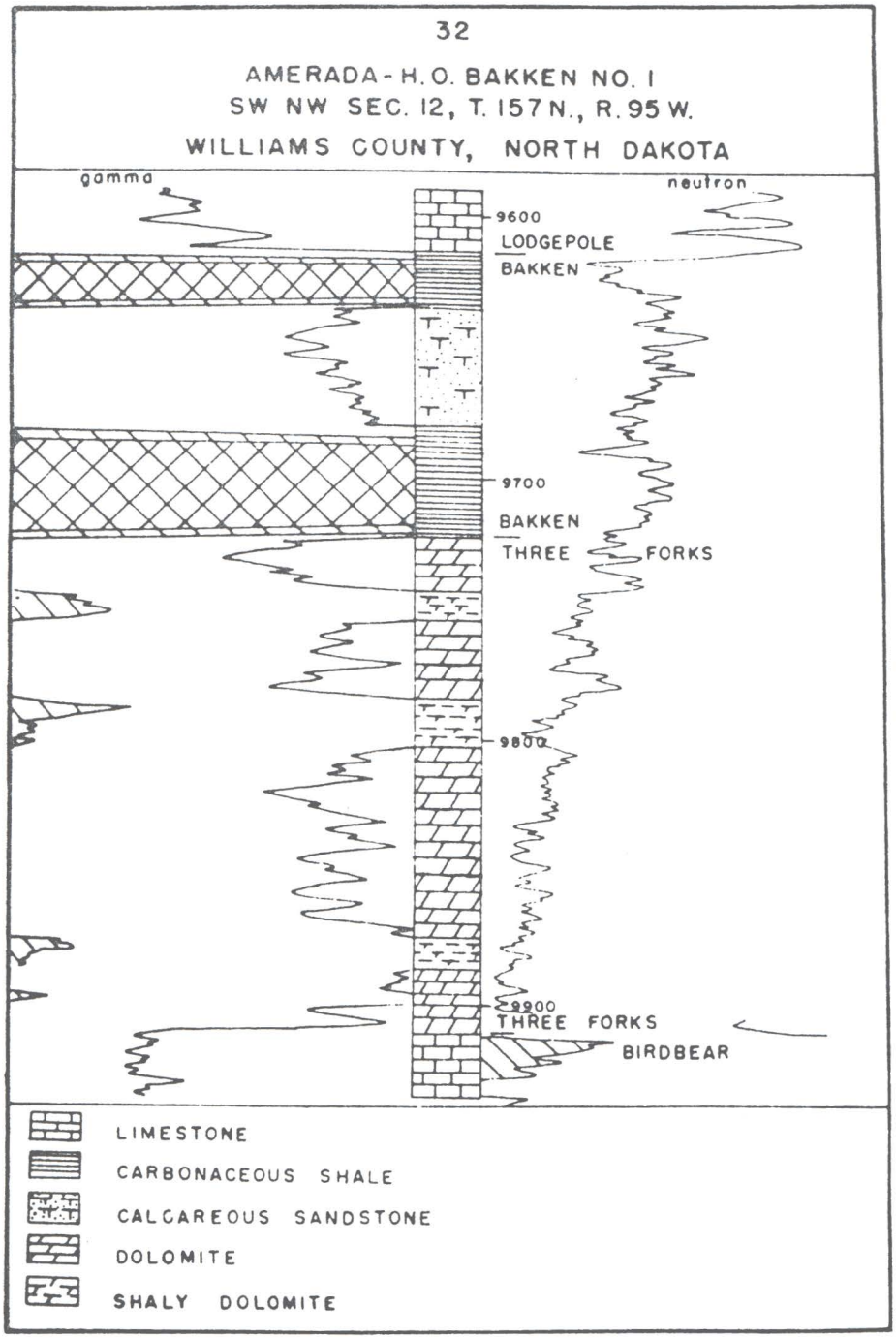


Fig. 3. Type section of the Bakken Formation in the Amerada Petroleum Corporation - H.O. Bakken No. 1 well (NDGS well no. 32) (From Kume, 1963, p. 30).

observed from the shales in the shallower portion of the basin (less than 7,000 ft. deep). The middle member displays more "normal" readings on the above mentioned logs; these readings are those characteristic of carbonates and fine-grained clastics which are well cemented. The log responses of the Bakken are displayed in Figure 4.

Areal Extent

In North Dakota the limits of the three members of the Bakken Formation display an onlapping relationship with each successively younger member being more extensive than the previous one (Fig. 5). The limit of the upper shale is believed to be a depositional limit, as the contact of this shale with the overlying Lodgepole has been said to be conformable (Heck, 1979, p. 4). The limit of the middle member is also thought to be a depositional one, as the upper shale appears to lie conformably on the middle member; but it is uncertain whether the limit of the lower shale was modified by erosion prior to or during deposition of the middle member. The middle member displays high energy depositional conditions in some parts (e.g. cross bedding), and thus it may be possible that modification of the lower shale depositional limit occurred. The onlapping relationship of the three members is most likely the result of transgression of the Late Devonian to Early Mississippian sea.

Structural Configuration

A structure contour map on top of the Bakken Formation reveals the basin geometry and shows major positive structural features of the Williston basin, such as the Nesson anticline and the Billings nose (Fig. 6). The Bakken is seen to be buried the deepest in McKenzie and

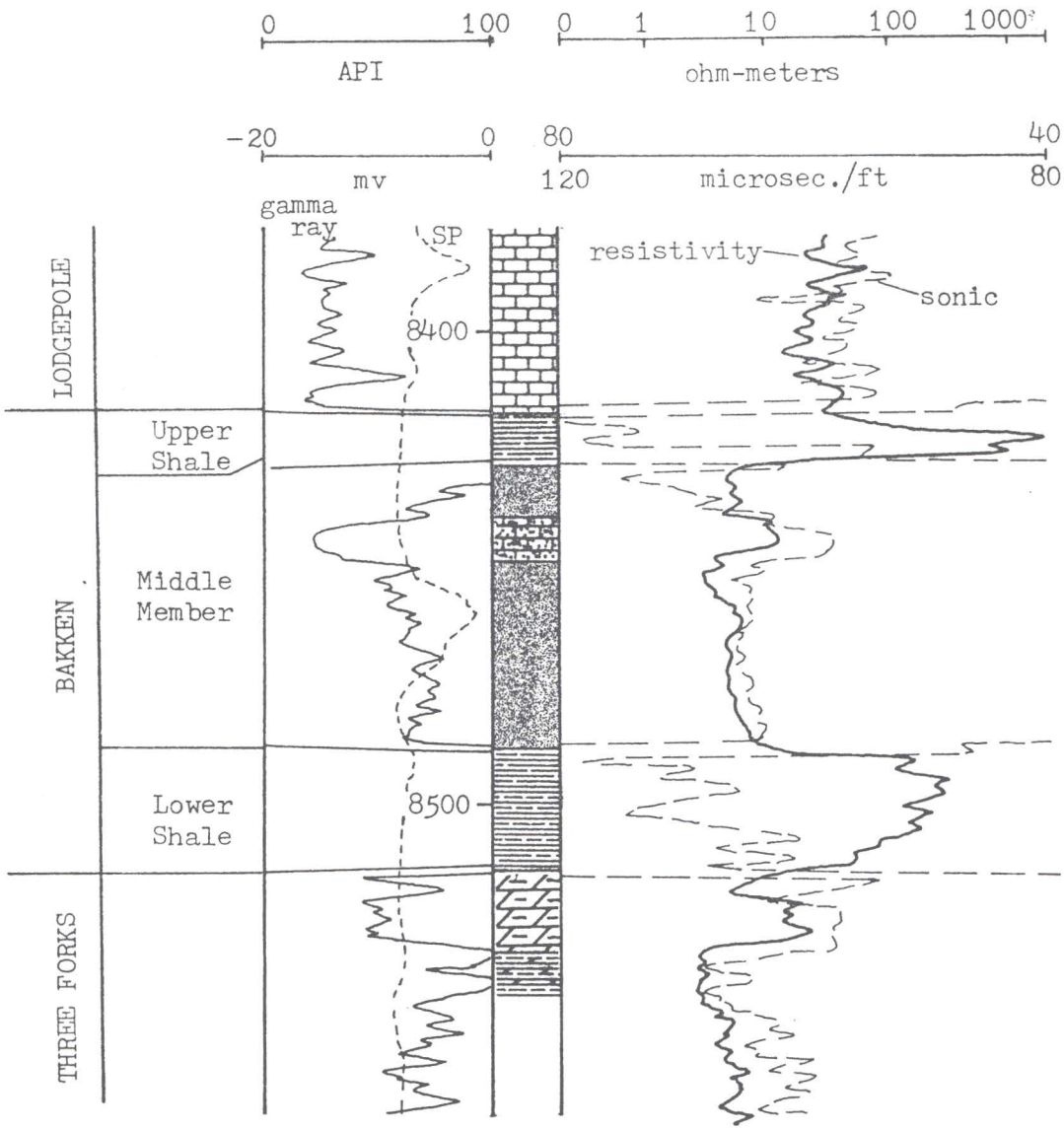


Fig. 4. Well logs from the Tipperary Oil and Gas Corporation - Olsen No. 1 well (NDGS well no. 6541), SE¼, SW¼, sec. 26, T. 160 N., R. 97 W., Divide County, North Dakota. Depths (from the surface) in feet.

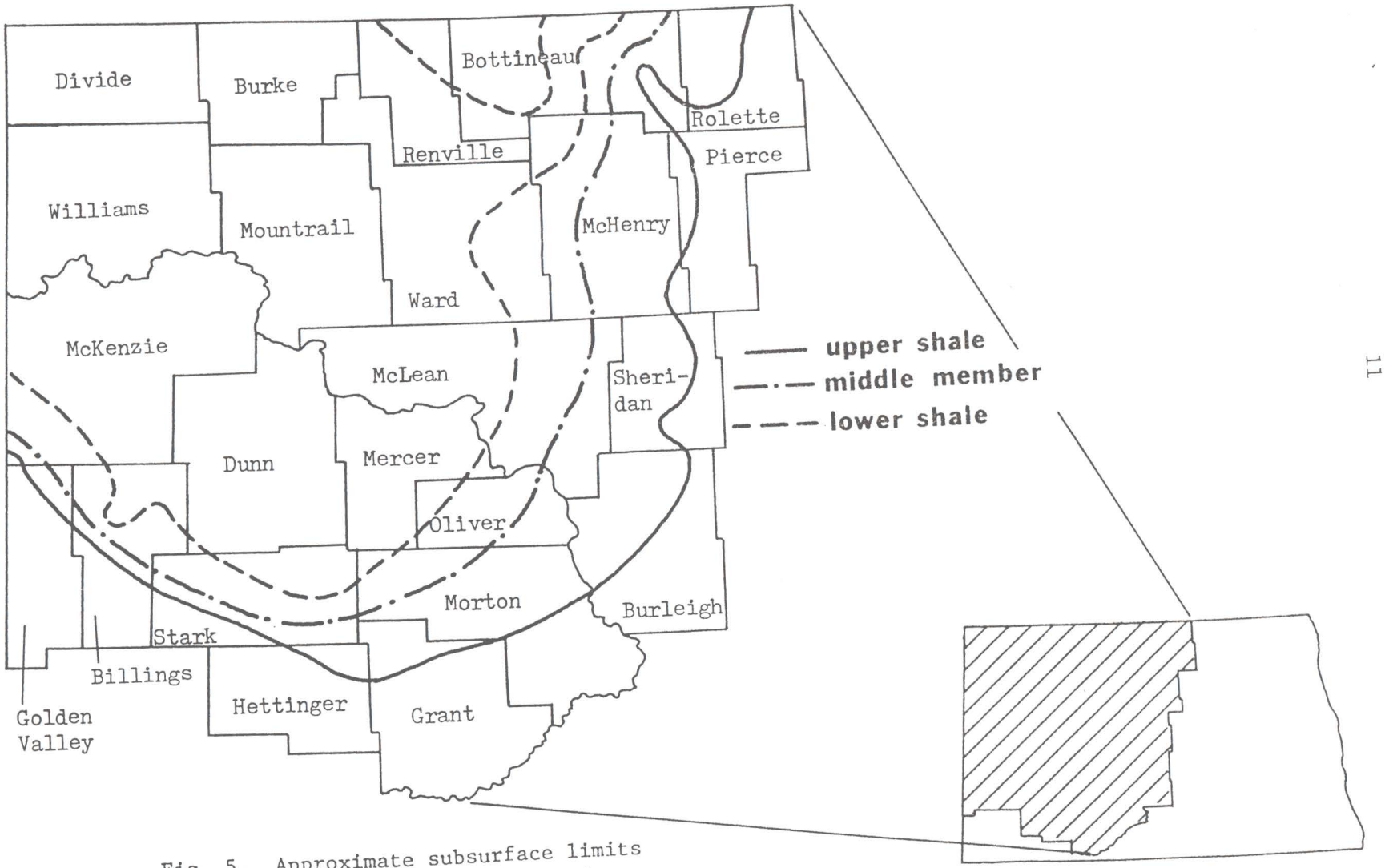


Fig. 5. Approximate subsurface limits of the three members of the Bakken Formation.

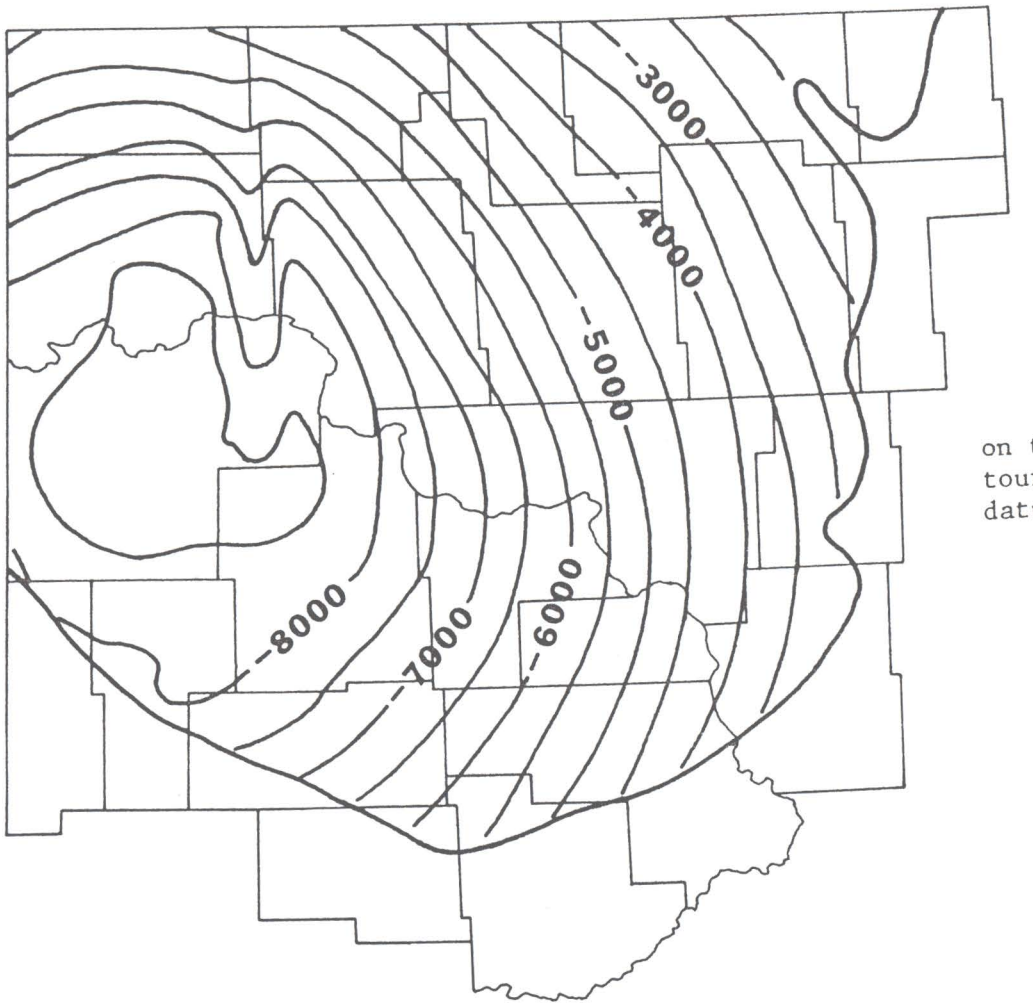


Fig. 6. Structure contour map on top of the Bakken Formation. Contour interval is 500 feet and the datum is sea level.

Dunn Counties and is shallowest in Rolette County. Figure 7 is a computer generated three-dimensional view of the surface on top of the Bakken which displays the Bakken's structural relationships. Well log tops of the Bakken, picked up by the author, were used as the data set for a computer program that plotted a raised surface image of these data.

Overlying Units

In North Dakota, the Bakken is everywhere overlain by the Lodgepole Formation which consists, in the section immediately above the Bakken, of dense dark gray to brownish-gray limestone and dark gray calcareous shale. Minor amounts of chert and anhydrite are also present in the limestone of the Lodgepole. The Lodgepole has a maximum thickness of 900 feet in eastern McKenzie County (Heck, 1979, p. 9).

A thin, black shale and black, organic-rich limestone occur above the Bakken in some parts of the area studied, namely in McKenzie, Billings, Dunn, and Mountrail Counties (Fig. 8). Fuller (1956, p. 25) reported a similar black shale bed in Saskatchewan. This dark shaly unit is usually separated from the upper Bakken shale by a medium gray to brownish-gray, dense limestone that is fragmental in some places, and has abundant pelmatozoan material. The Routledge shale occurs locally above the Bakken in Rolette County (Plate 1) and is similar in lithology to the Bakken shale (Stanton, 1956), but the Routledge has a slightly lower reading on the gamma ray log. Stanton believed the Routledge to be the result of continuation of Bakken-type shale sedimentation in areas of significant salt collapse of the underlying Devonian Prairie Formation.

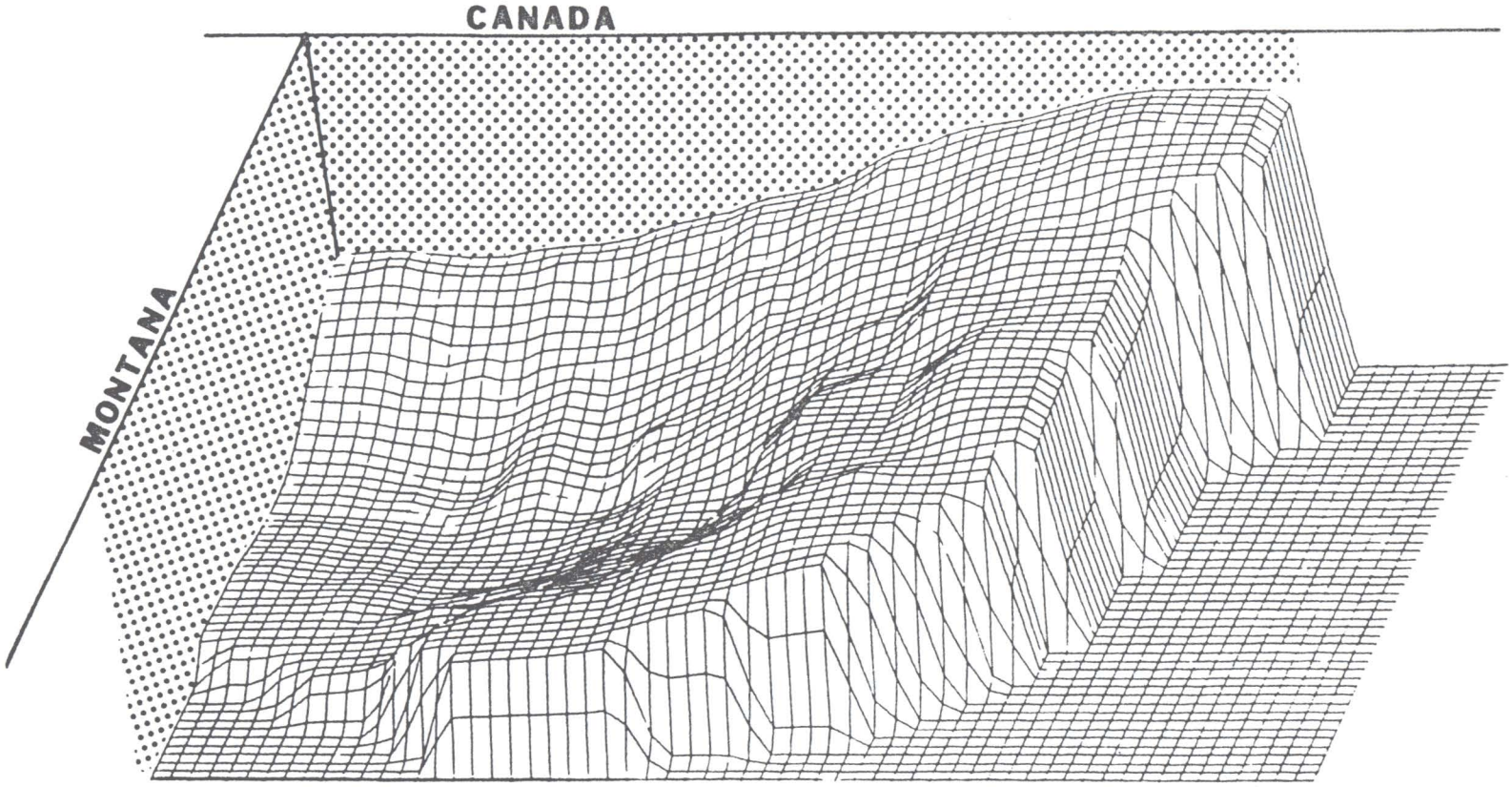


Fig. 7. Computer generated diagram of the surface on top of the Bakken Formation, displaying the structure of this surface. The raised surface covers only the extent of the Bakken Formation within North Dakota.

Underlying Units

In the area of study, the Bakken is everywhere underlain by the Three Forks Formation of Devonian age, which has a maximum thickness of approximately 250 feet in eastern McKenzie County. The Three Forks is composed of thinly interbedded greenish-gray and reddish-brown shales, light brown to yellow gray dolostone, gray to brown siltstone, quartzose sandstone, and minor occurrences of anhydrite (Figs. 3,8) (Kume, 1963, p. 32). The contact between the Bakken and Three Forks appears conformable in the deeper portions of the basin and unconformable on the basin flanks. Well log cross sections of the Bakken-Three Forks interval (Plates 1,2) display the relationships between the Bakken members and four informal members of the Three Forks. The four informal members of the Three Forks used in this study are similar to the subdivisions made by Fuller (1956, p. 19) in Saskatchewan. Throughout most of the area studied, the Bakken has a structural attitude parallel to members of the Three Forks, and a conformable contact with the Three Forks is inferred. On the flanks of the basin, truncation of upper members of the Three Forks occurs beneath the Bakken and an angular unconformity is inferred for this area (Plates 1,2). The Bakken-Three Forks contact, as observed in cores of the deep basin area, displays an abrupt lithologic change, but no features of erosion were observed except in NDGS (North Dakota Geological Survey) well no. 7579 in southwestern McKenzie County where a slight undulatory contact between the Three Forks and the Bakken (middle member) can be seen. In Saskatchewan an unconformity between these two formations was suggested by Fuller (1956, p. 22) where a pebble bed occurs at the base of the Bakken in several wells.

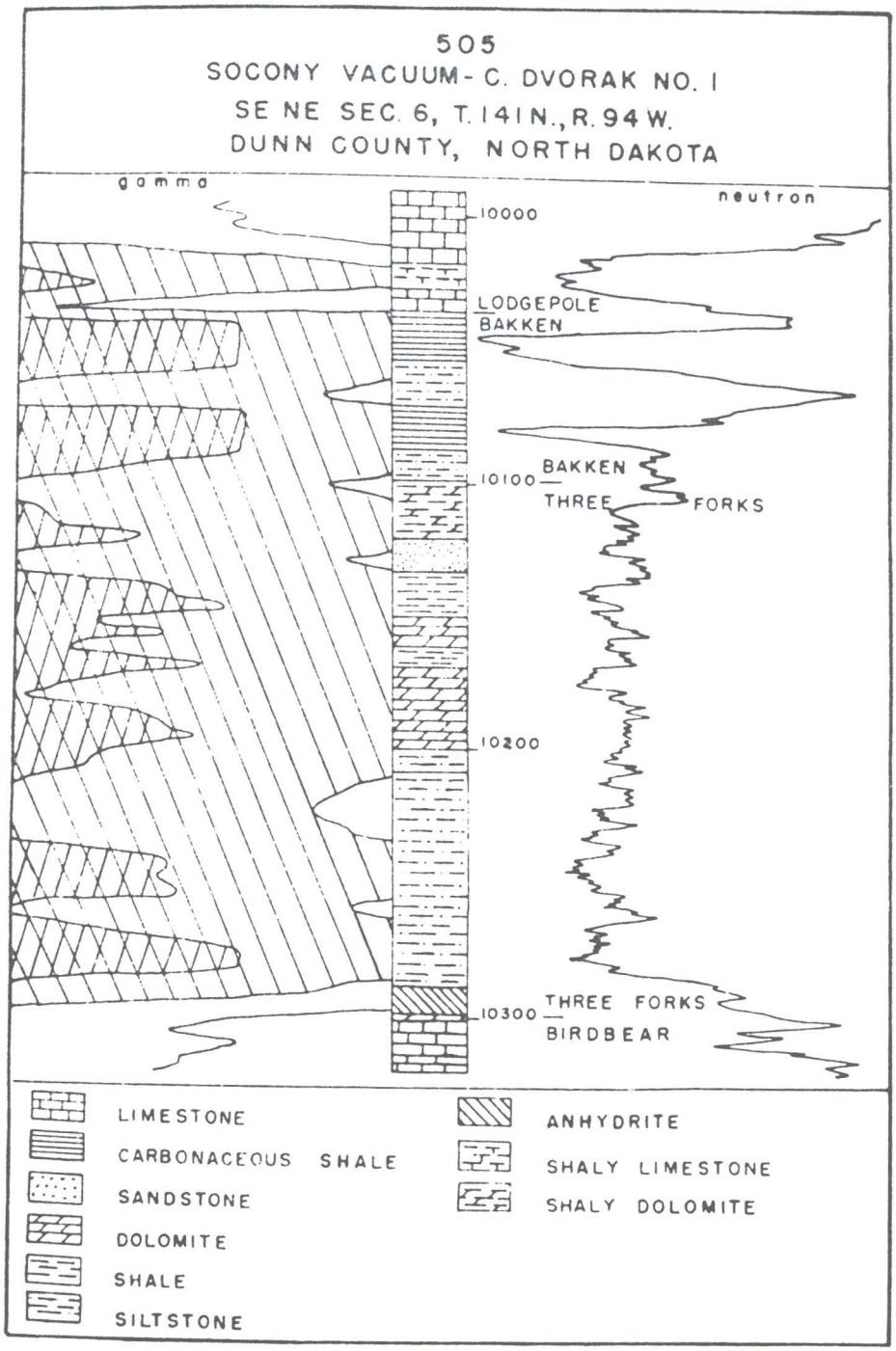


Fig. 8. Well log responses and lithology of the Bakken and Three Forks Formations in the Socony Vacuum Oil Company - C. Dvorak No. 1 well (From Kume, 1963, p. 43).

A quartzose sandstone in the upper Three Forks, informally referred to by workers in the Williston basin as the "Sanish Sand", locally underlies the Bakken. Kume (1963, p. 77) described this sandstone in a core from the J.M. Donahue No. 1 well in Williams County (NDGS no. 999) as a colorless, fine-grained, slightly calcareous, quartzose sandstone. Kume claimed the sandstone is present in scattered wells in McKenzie, Williams, Mountrail, and Bottineau Counties and has an erratic occurrence that might be indicative of beach sand deposits or shallow-water sand bars.

Thickness

The Bakken Formation ranges in thickness from a maximum of 145 feet in western Mountrail County to a feather edge along its depositional limit. The depocenter for the formation is located immediately east of the Nesson anticline and is elongated in a nearly north-south direction (Fig. 9). In the eastern portion of the study area, the formation thickness is highly variable. Large increases in thickness are probably the result of solution and subsequent collapse of salts in the Middle Devonian Prairie Formation. Erosion on the surface of the Three Forks prior to Bakken deposition may also have contributed to thickness changes of the Bakken in this area, as the Bakken would be thicker in low areas of this erosional surface and thinner over high areas.

Thinning of the Bakken in certain areas can be interpreted to represent structural highs active at the time of Bakken deposition. Three prominent areas that are interpreted as positive can be seen in the eastern portion of the study area (Fig. 9): one in northeastern Renville County, one in southeastern Ward and southwestern McHenry

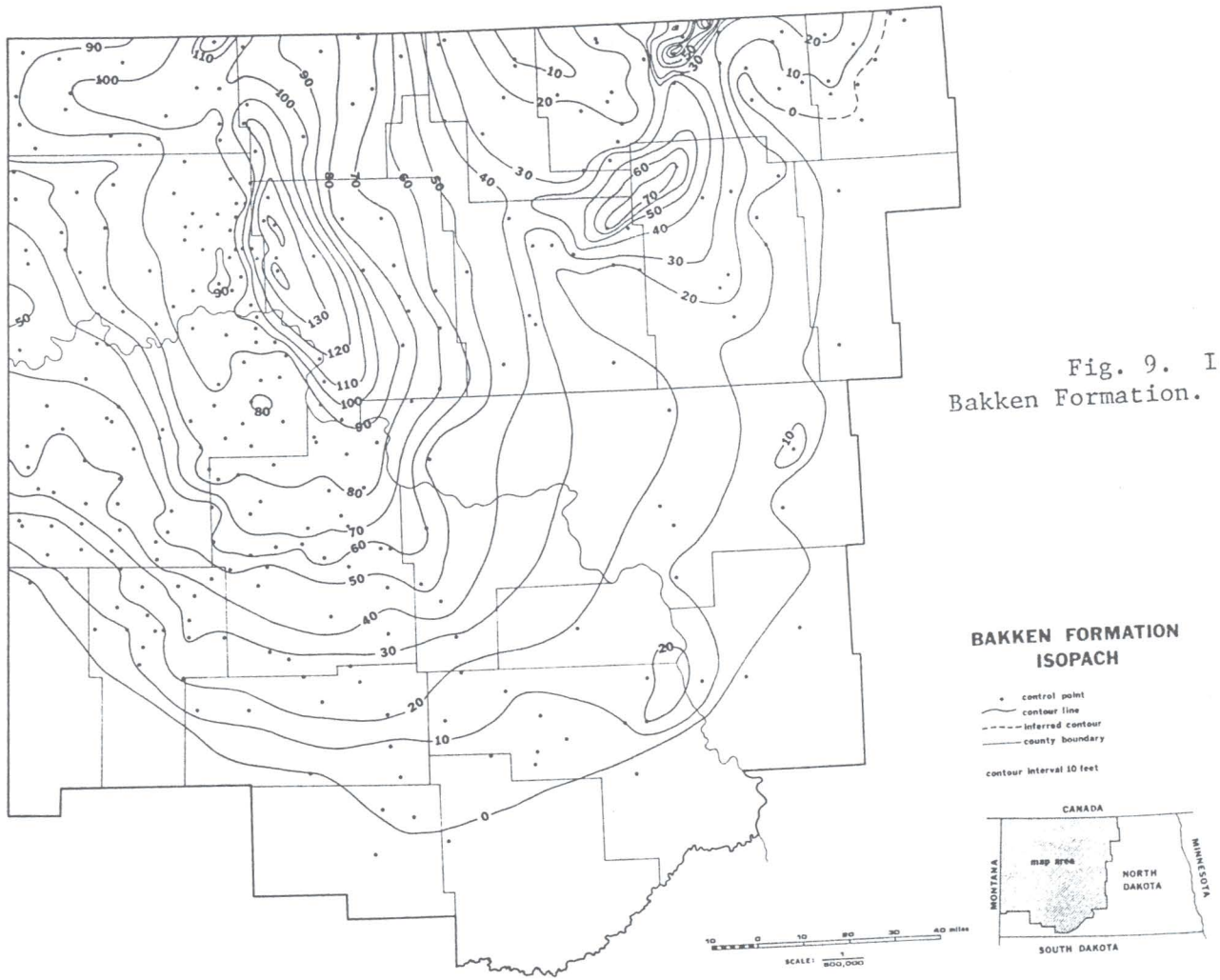


Fig. 9. Isopach map of the Bakken Formation.

Counties, and one in southeastern Bottineau County where the Bakken is absent in a narrow area trending northwest-southeast. The Nesson anticline does not appear to have been active during this time, as no significant thinning of the Bakken is observed in that area.

The isopach map of the lower Bakken shale (Fig. 10) shows the Bakken depocenter to be well developed during the time of deposition of the lower shale where a maximum lower shale thickness of 50 feet occurs. A peculiar curved extension with abrupt thickening of the lower shale occurs in the northeastern portion of the study area and surrounds a large positive area in Renville and Bottineau Counties. This thickening is probably the result of salt collapse in the Devonian Prairie Formation or it may be due to extra deposition of the lower shale in a pre-Bakken paleochannel (F.D. Holland, Jr., personal commun., 1982).

The middle member isopach map (Fig. 11) also displays a well-defined depocenter in western Mountrail County where the middle member reaches a maximum thickness of 85 feet. Salt solution in the Prairie Formation and erosion on the Three Forks surface probably contributed to the abrupt thickness increases in Bottineau and northwestern McHenry Counties. The high in western Bottineau County was still active in middle Bakken time and a high in central McHenry County became evident at this time. A small area of thin middle member in eastern McKenzie County may be the result of some uplift on the southern end of the Nesson anticline.

The upper shale isopach map (Fig. 12) shows the thickness distribution of the upper shale to be much more even than that of the two previous members. The apparent depocenter in eastern McKenzie

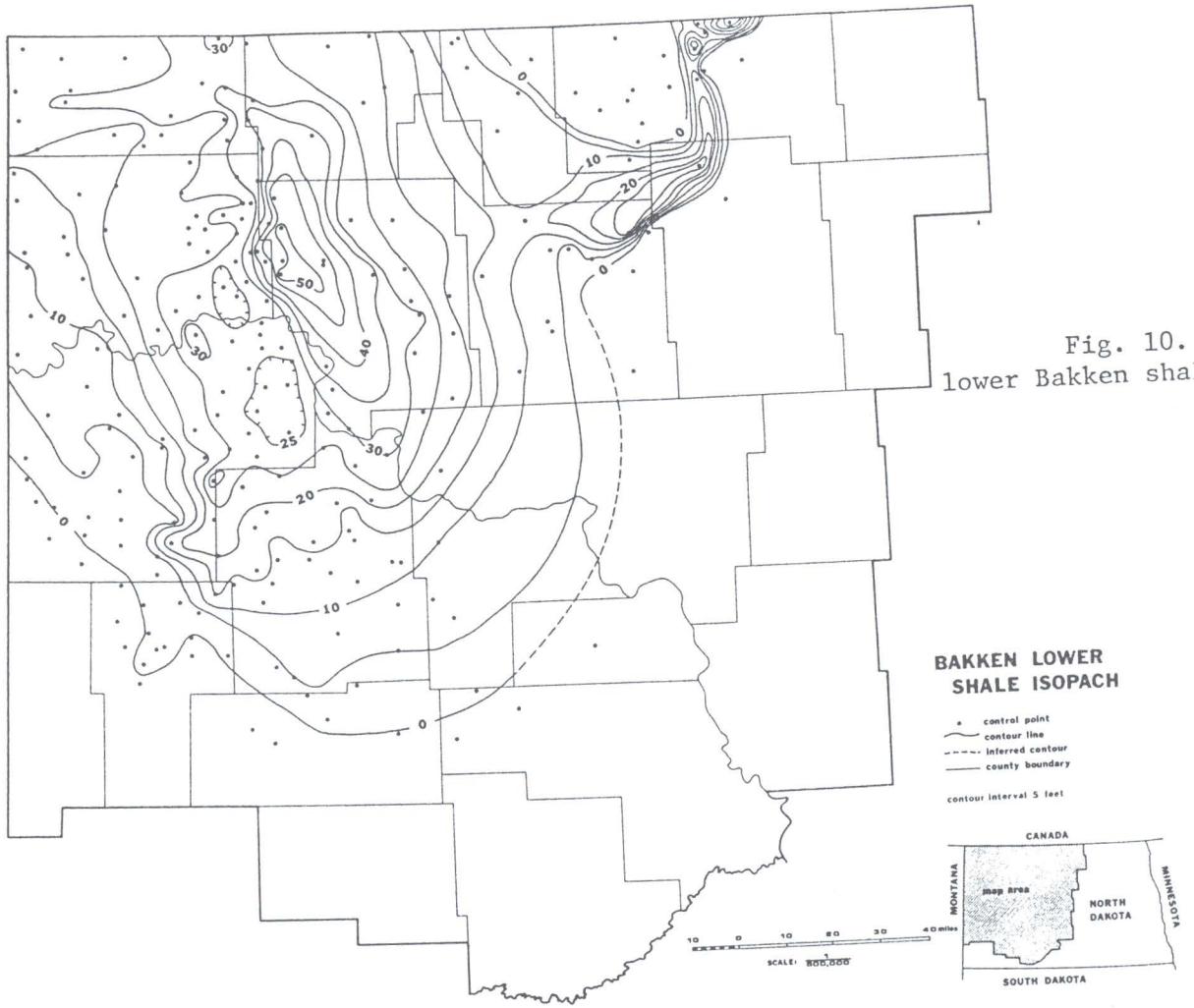


Fig. 10. Isopach map of the lower Bakken shale.

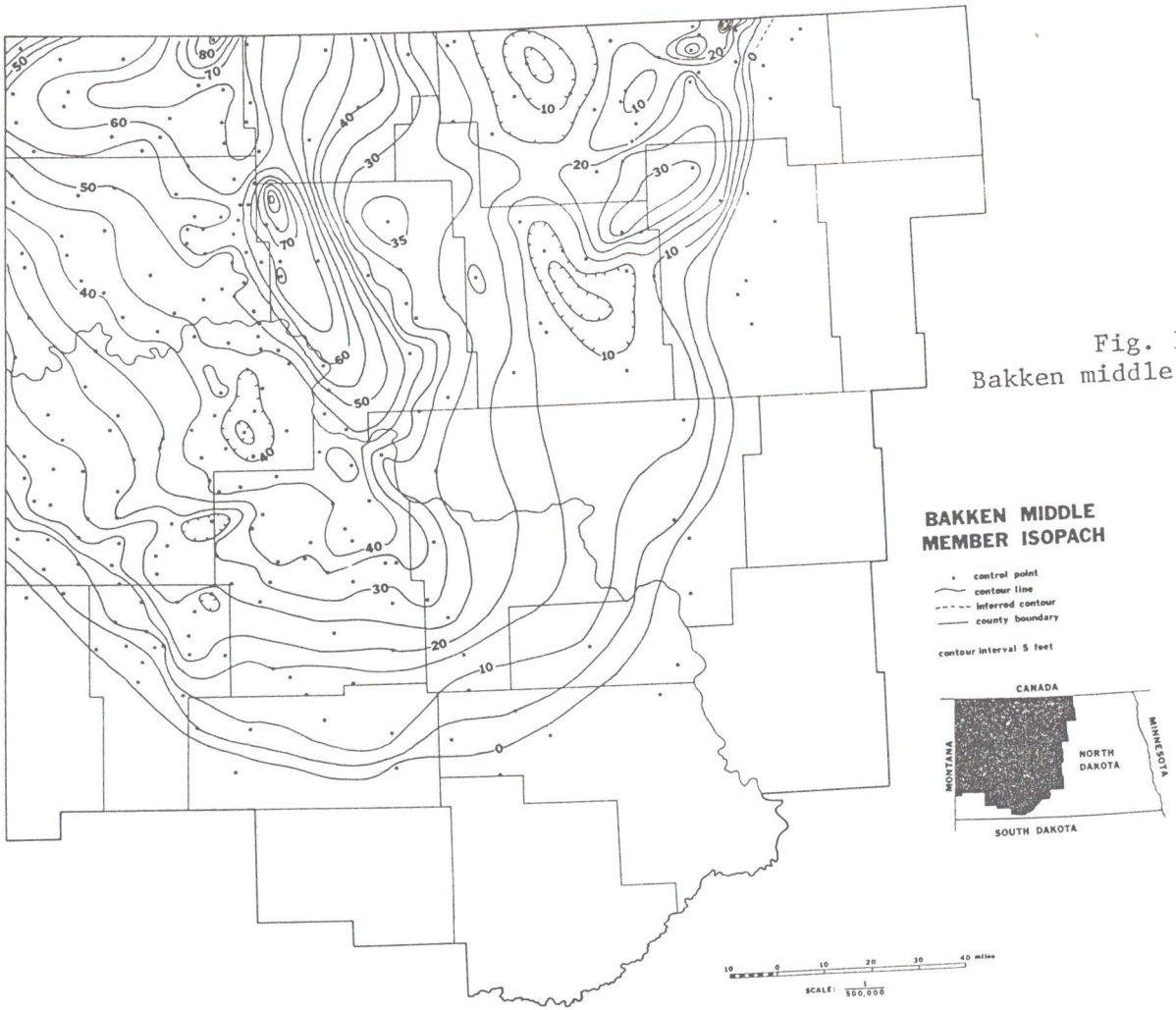


Fig. 11. Isopach map of the Bakken middle member.

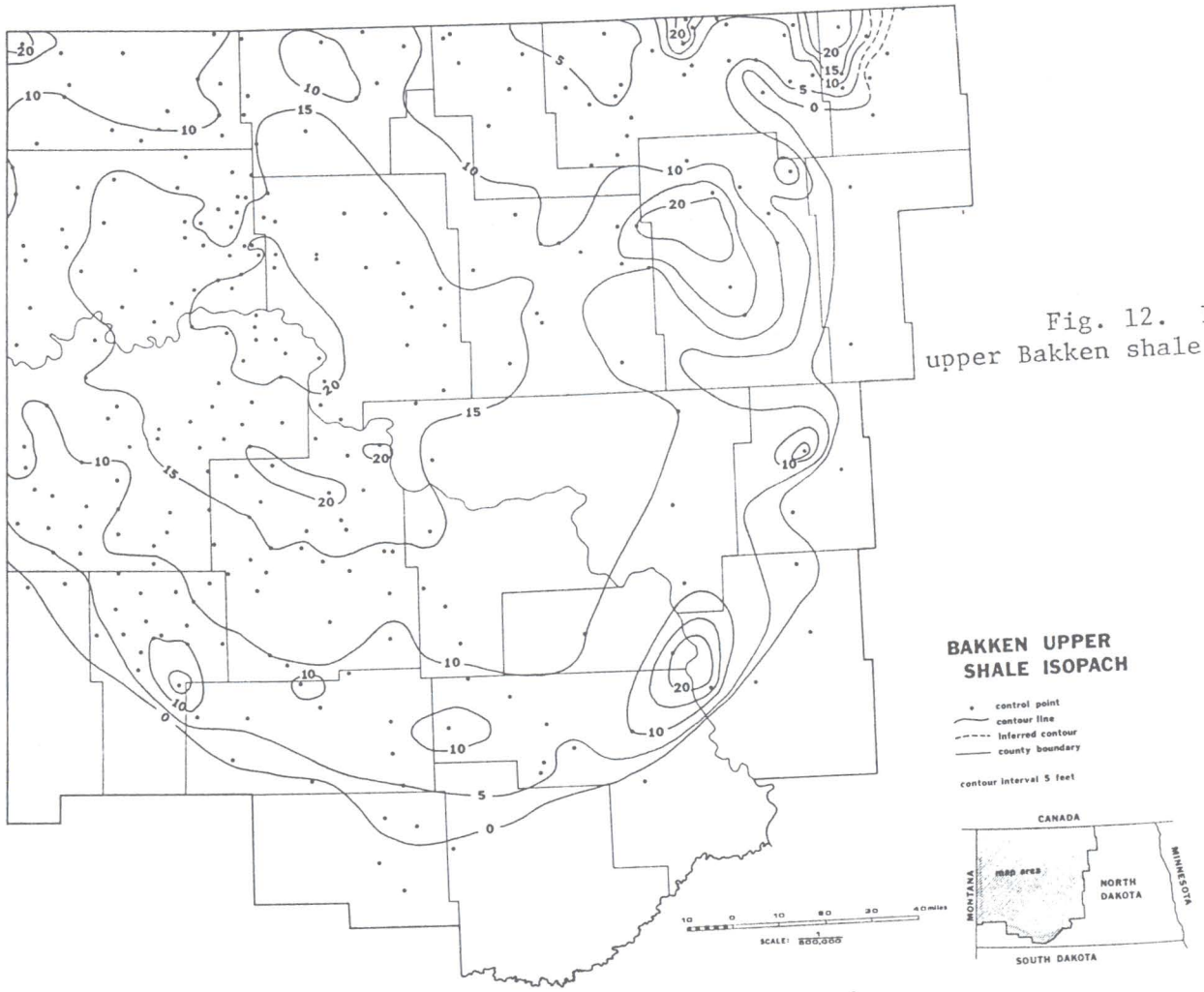


Fig. 12. Isopach map of the upper Bakken shale.

County and southwestern Mountrail County is very broad and not well defined. The surface upon which the upper shale was deposited appears to have been very flat over a large area and subsidence in the area of the formation depocenter was reduced during this time. Areas of abrupt thickness increases in the eastern portion of the study area are, again, probably the result of salt collapse in the Prairie Formation and erosion on the Three Forks.

Bakken Core Descriptions

Figure 13 shows the lithology and other important characteristics as seen in a typical core of the formation. Additional core descriptions of this study are included in Appendix C. The following sections describe, in some detail, the character of the Bakken as seen in cores.

Lithology

The upper and lower Bakken shales are hard, siliceous, pyritic, fissile, often noncalcareous, organic-rich (average of 11.33 weight percent of organic carbon; Appendix E), and dark black (N1) when wet. The shales often break with a smooth, conchoidal to flat horizontal fracture. The conchoidal fracture is probably due to a high quartz content (detrital grains and secondary cement) in the shales. Pyrite is commonly concentrated in lenses and laminations, or is finely disseminated throughout the shales. The upper and lower shales are identical in lithology and show remarkable lithologic uniformity throughout their extent. Two thin (3 feet thick), black limestones occur within the lower shale in cores from NDGS well nos. 1748 and 1405 in McKenzie County. These limestones are generally coarsely crystalline and much less rich in organic material (0.87 weight percent organic

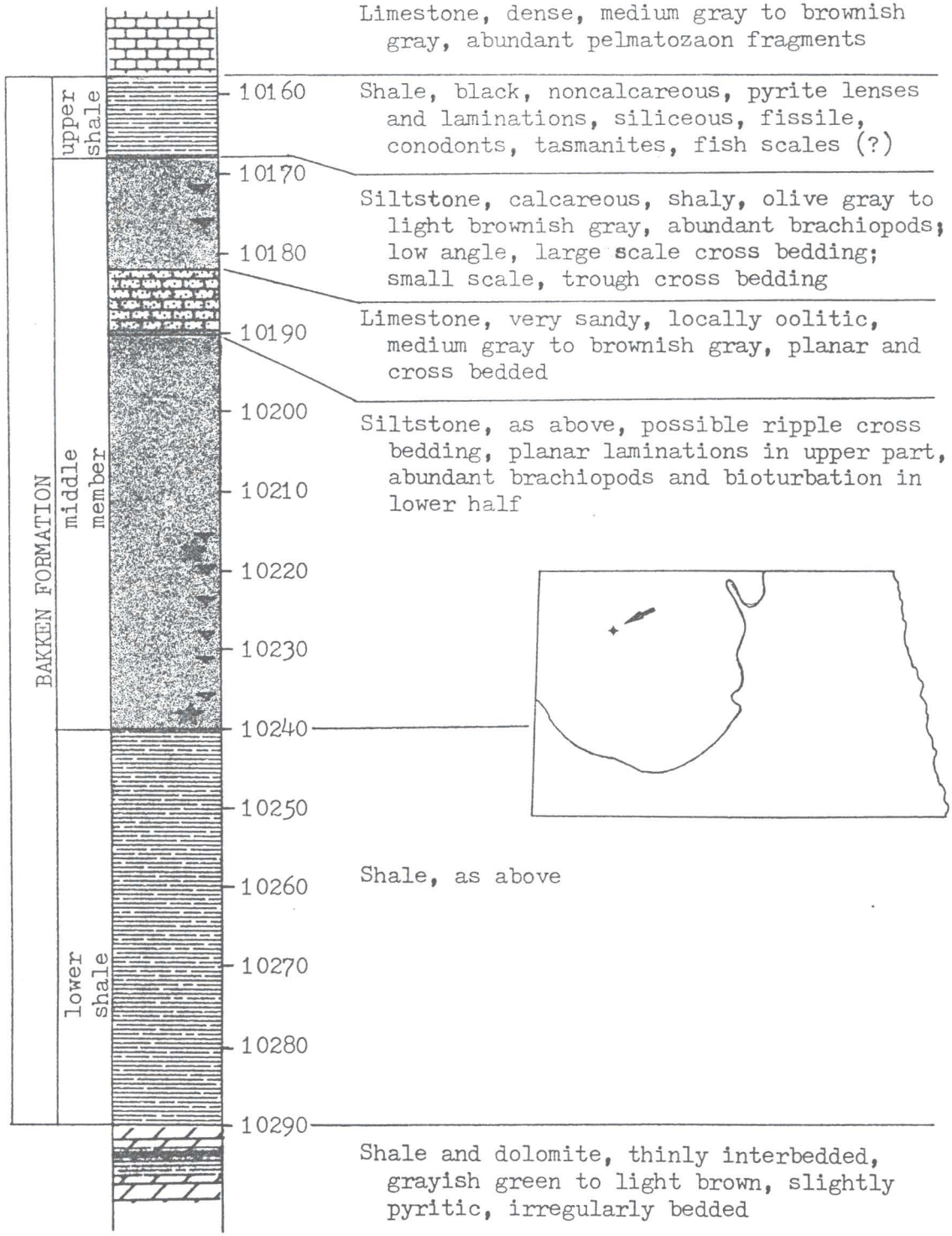


Fig. 13. Core description of the Bakken Formation and immediately adjacent rocks from the Shell Oil Company - Shell-Texel No. 21-35 well (NDGS well no. 5088), NE¼, NW¼, sec. 35, T. 156 N., R. 93 W., Mountrail County, North Dakota.

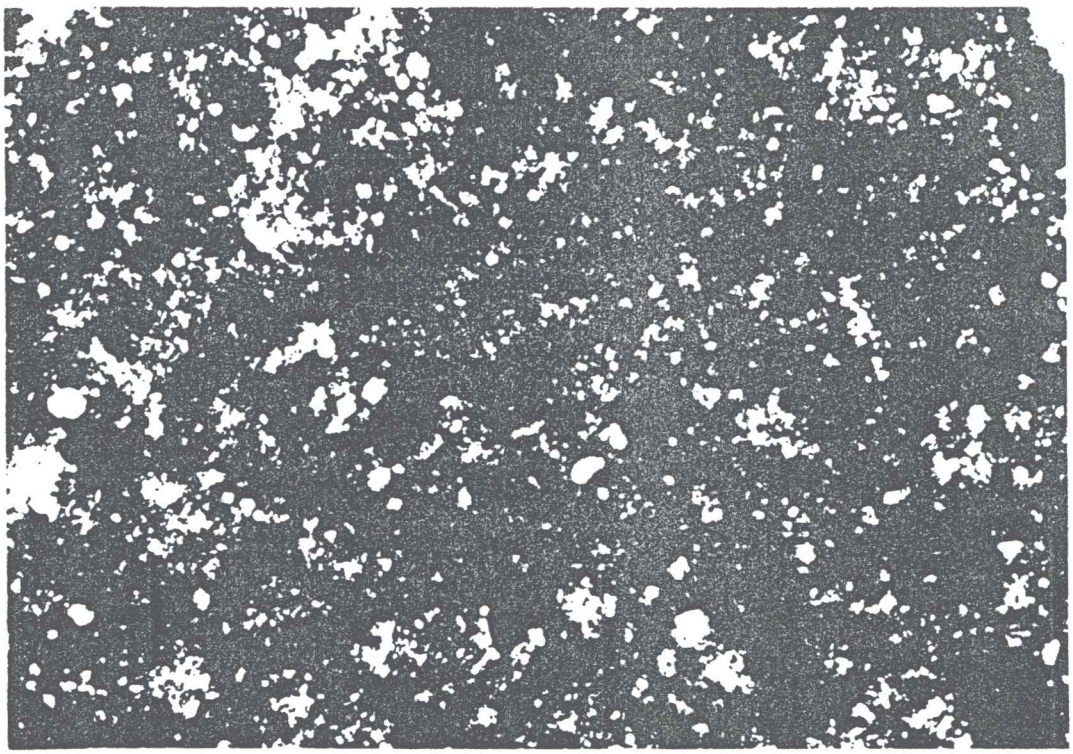
carbon; Appendix E) than the shales.

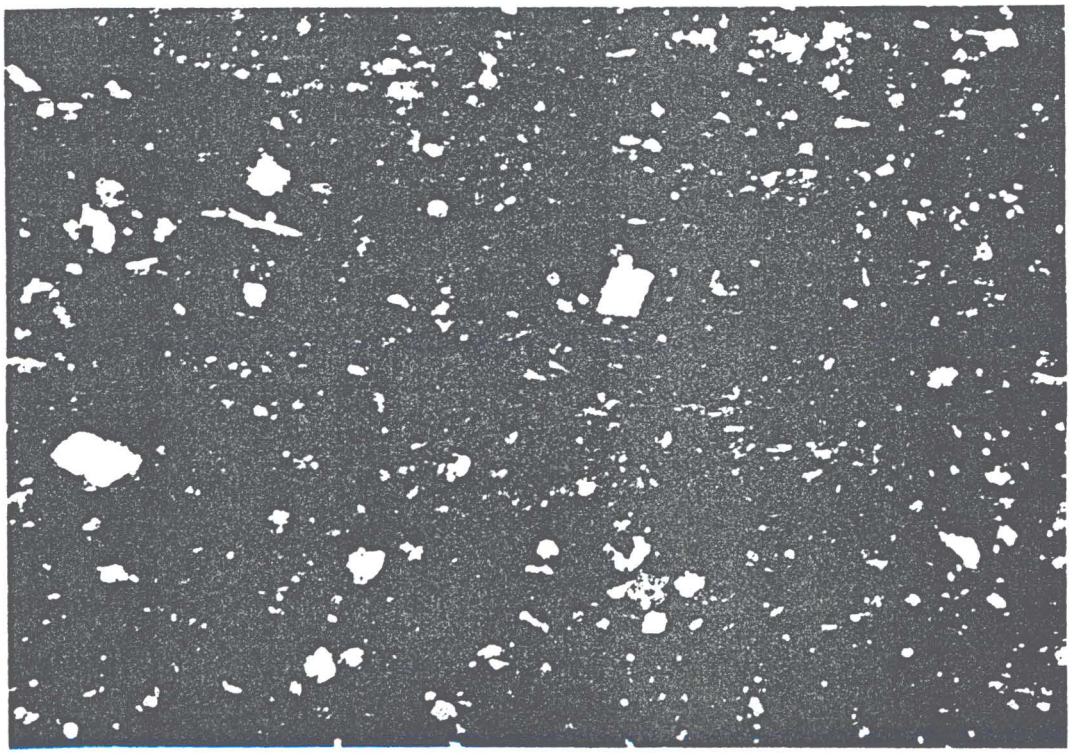
In thin section, the shales are seen to be composed mostly of dark indeterminate material (Fig. 14) of which a large percentage is probably organic material. This organic material is distributed rather evenly in the shales and not concentrated in lenses or laminations. Quartz appears to be the dominant mineral present as seen in thin section and on X-ray diffraction charts. Detrital grains are scattered throughout and some silica-filled fractures occur. Some calcite and dolomite can be seen in thin section. It is uncertain how much of the Bakken shale is composed of muscovite, illite, or other clay minerals, but this amount seems to be less than would be expected in a "normal" shale, as the muscovite/illite peak on X-ray diffraction charts is low. Results of a scanning electron microprobe chemical analysis (Webster, 1980) of the Bakken shale show silica (81.25 percent), aluminum (10.48 percent), magnesium (1.91 percent), iron (0.97 percent), and potassium (2.70 percent) to be the dominant chemical constituents of the shale.

The middle member of the Bakken varies in lithology and includes calcareous siltstone, sandstone, dolostone, silty limestone, and oolitic limestone. The sandstone is usually brownish-gray (5YR 4/1), fine- to medium-grained, subrounded to subangular, and calcareous. The limestones are brownish-gray (5YR 4/1) to medium gray (N6), silty, argillaceous, and in one unit (Fig. 13) are occasionally sandy and oolitic. Siltstone is the predominant lithology of the middle member. The siltstones are very calcareous to noncalcareous, often dolomitic, argillaceous, olive gray (5Y 4/1) to medium gray (N5), and their grain size often approaches very fine sand. All lithologies within the

Fig. 14. Photomicrographs of the Bakken shale. A. Photomicrograph in plane polarized light of the lower Bakken shale in NDGS well no. 5088 at a depth of 10248 feet. The magnification is 100X. The dark, indeterminate material is probably mostly organic matter and the light colored material is mineral matter (mostly quartz).

B. Photomicrograph with crossed polars of the upper Bakken shale in NDGS well no. 5088 at a depth of 10168 feet. The magnification is 100X. The light material is mostly quartz. A dolomite rhomb is visible in the center of the photograph.





middle member are very well cemented with calcite and silica, and have low permeability and porosity.

Bedding Features

The Bakken shales have very even, planar laminations which are usually accented by the presence of pyrite. In some cases the laminae appear slightly disrupted. Where bedding is not apparent, the shales are massive.

The middle Bakken displays many different types of bedding including small scale trough cross bedding, planar cross bedding, wave ripple cross lamination, irregular laminations, and planar laminations. Bidirectional (herringbone) cross bedding is present in two cores (NDGS well nos. 4508 and 527) of the middle member. Soft-sediment deformation in the form of small folds and faults is apparent in some cores.

Fossils

Conodonts, the most common fossil observed in the Bakken shales, are very abundant locally, often concentrated in thin beds. Tasmanite (tasmanite palynomorphs) amber colored spores are also abundant locally. These spores are believed to be the remains of unicellular, planktonic, marine algae (Wall, 1962). Possible fish scales are also seen in a number of cores. Fuller (1956, p. 18) reported the presence of brachiopods of the genus Lingula in the Bakken shales of Saskatchewan. It is possible that inarticulate brachiopods in the Bakken shale of North Dakota have been mistakenly identified as fish scales. A large piece of terrestrial (woody) plant material is present in the upper shale in NDGS well no. 8177 in western Ward County. This type

of plant material is very rare in the Bakken shales, though.

Brachiopods are the most abundant fossils in the middle member with pelmatozoan fragments occurring to a lesser extent. Bioturbation is common and a few distinct burrows can be made out.

Other Features

Natural fractures are present in many of the cores of the Bakken. Calcite and silica mineralization line, or completely fill, many of these fractures (Fig. 15). Most of the fractures are oriented within 10 degrees of vertical, although some are horizontal. The horizontal fractures were observed in the Bakken shales only, and these are probably the result of fissility of the shale. Very straight and thin, calcite-filled fractures are present in the black shales of NDGS well nos. 1202, 4340, and 527. Fractures were more commonly observed in the shales than in the middle member lithologies.

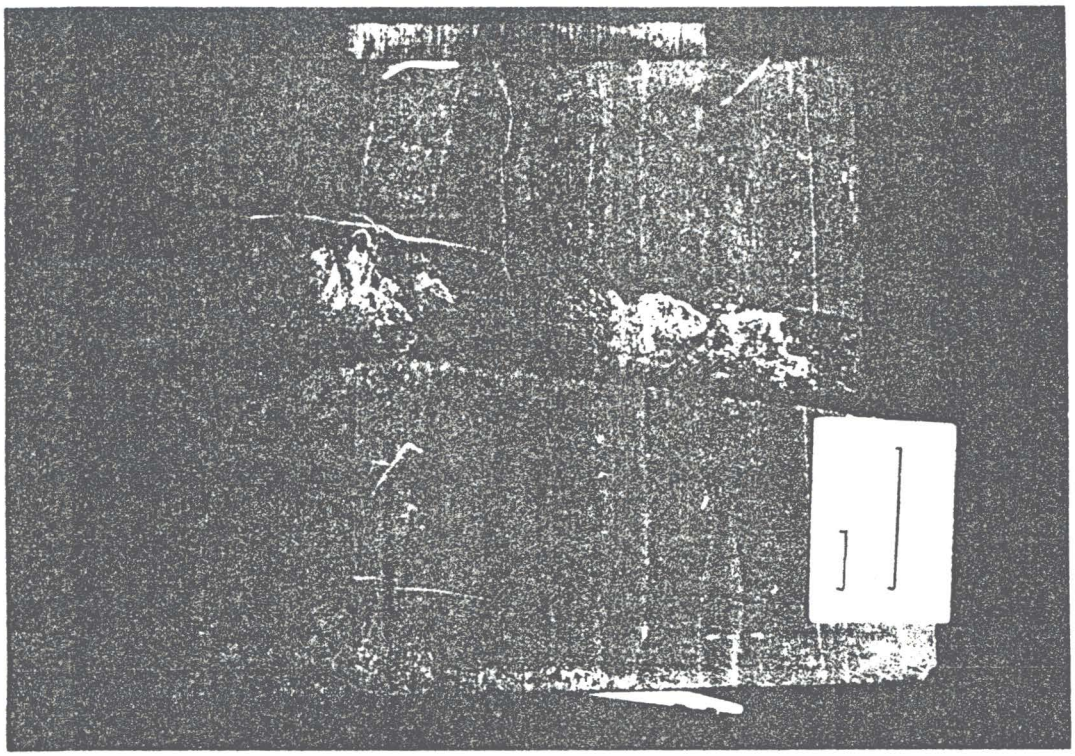
Depositional History

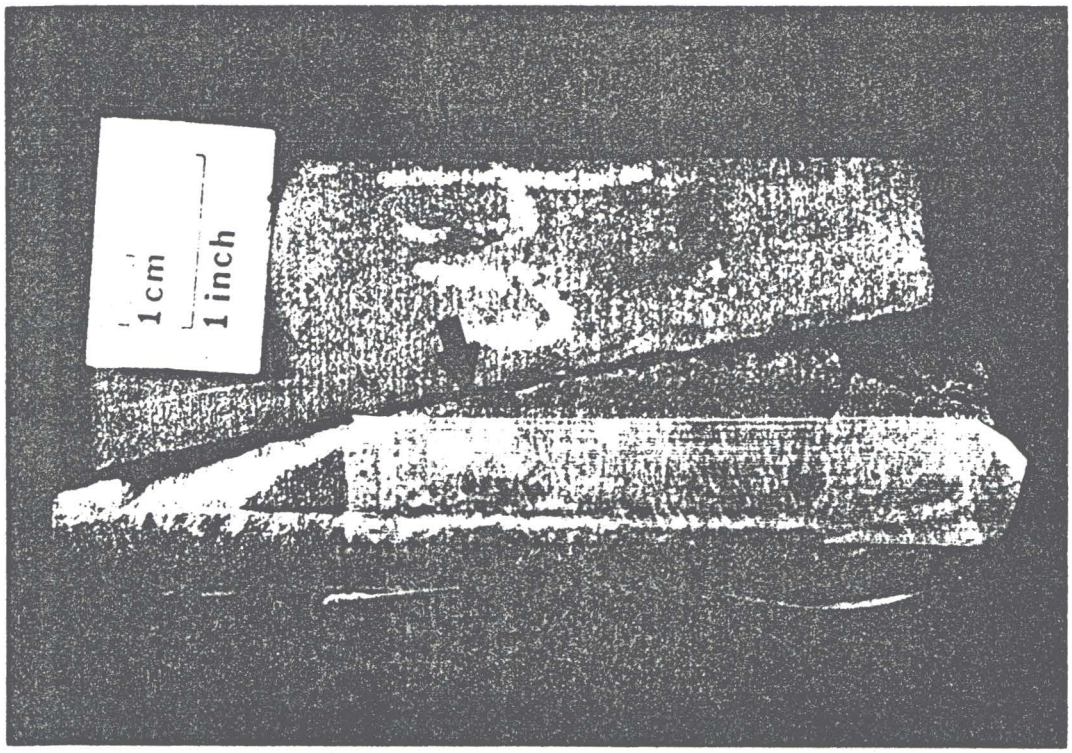
Devonian sedimentation in the Williston basin ended in Late Devonian time with the deposition of shallow marine to terrestrial sediments of the Three Forks Formation (McCabe, 1959, p. 43) during a marine regression to the northwest. During Late Devonian to Early Mississippian time, major uplift and erosion occurred along the margins of the Williston basin (Sandberg, 1964, p. 38). The sea probably did not completely withdraw from North Dakota at this time; rather it withdrew to the approximate area covered by the lower Bakken shale. This is suggested by the apparently conformable contact between the Three Forks and Bakken Formations in the deeper portions of the basin. Transgression of the sea again began in lower Bakken shale time.

Fig. 15. Photographs of Bakken cores illustrating possible fracturing.

A. Upper Bakken shale from NDGS well no. 7887 at a depth of 10792 feet. Large open vertical fracture is shown running through the center of the core, with white calcite lining the fracture surface. Other small, calcite-filled fractures can be seen in the upper half of this slabbed core piece.

B. Photograph of siltstone of the Bakken middle member from NDGS well no. 8474 at a depth of 10371 feet. A straight, open fracture (indicated by arrow) can be seen through the center of the core at a steep angle. This fracture is unmineralized.




1 cm
1 inch

The nature of the Bakken shales indicates a pronounced basin-wide change in depositional environment from highly oxidizing conditions during Three Forks time to highly anoxic during part of Bakken time. As the sea transgressed in early Bakken time, some type of change occurred in basin geometry, growth of organics, climate, or water circulation, that caused anoxic, possibly stagnated conditions. These anoxic conditions ended in middle Bakken time as an influx of coarser clastics into the basin occurred. The source of the clastics is unknown, but a source to the north and northwest seems likely, based upon Bakken isopachs and a northward-increasing clastic ratio of the middle member (Nordquist, 1953, p. 74). The middle member has a fauna and bedding features indicative of a normal shallow marine to nearshore marine depositional environment.

Transgression of the sea continued in middle and upper Bakken time as evidenced by the onlapping relationship of the Bakken members (Fig. 5). Several minor regressions may have occurred in the study area during middle Bakken time, as Christopher (1962) suggests for the Bakken in Saskatchewan. No direct evidence for these possible regressions (and resulting unconformities) was observed in this study.

Anoxic conditions returned to the basin with deposition of the upper shale as transgression continued. Normal, oxygenated water conditions then prevailed in Lodgepole time as normal carbonate sedimentation resumed in the basin.

Depositional Environment

The exact depositional environment for black shales such as the upper and lower Bakken is problematical. Such shales can form

under conditions varying from deep marine waters to terrestrial swamp.

The possible depositional environments proposed by previous workers include a vast marine swamp with restriction of circulation due to prolific organic development (McCabe, 1959); a stagnant, marginal-marine, lagoonal environment (Raasch, 1956); and a deep-water, marine environment with deposition below wave base (MacDonald, 1956).

The planar and thin laminations observed in the Bakken shales suggest deposition in very quiet waters, possibly below wave base of open water. The presence of planktonic algal spores (tasmanites), fish scales (?), conodonts, and inarticulate brachiopods indicates marine to marginal-marine water conditions. The high amounts of organic material and pyrite indicate chemically reducing and euxinic depositional conditions. The depositional environment of the Bakken shale would also have to have been very uniform over a large area to account for the widespread lithologic similarity of the shales. The great predominance of amorphous-sapropelic organic matter (probable algal or phytoplankton origin) over terrestrial (woody or humic) material (see section on results of kerogen typing and Appendix G) suggests an offshore marine depositional environment.

Several possible depositional environments that result in anoxic conditions are briefly discussed here. The first includes deposition in relatively "deep" (200-400? feet) marine waters, below wave base as proposed by MacDonald (1956). Normal circulation of the epeiric sea would have been cut off, in this model, by some type of barrier to the northwest that blocked the Williston basin from communication with open marine waters. The algae, fish, and other

marine organisms lived near the sea surface where oxygenated water and nearly normal circulation prevailed. Deposition of the black shale occurred as sediment and organic material settled through the water column to the quiet and anoxic bottom waters. A modern analog to this type of depositional environment might be the anoxic sedimentation taking place today in the Black Sea.

A model of upwelling, oxygen-poor, deep marine waters as the sea transgressed onto the craton might be another explanation for the depositional environment of the Bakken shales. This model has been proposed to explain other organic-rich shales by Heckel (1977), Parrish (1982), and Demaison and Moore (1980). Upwelling in the epeiric Bakken sea would require a minimum depth of 165 feet (Parrish, 1982, p. 758) and the right paleogeographic positioning of the Bakken sea to give rise to prevailing wind directions that would transport surface water away from shore and thereby set up shoreward circulation of deep (oxygen-poor) waters. Upwelling of this anoxic water near the paleoshoreline would have caused prolific organic development, such as plankton blooms, in the area of upwelling. This organic matter would have then settled through the water column, as it was being carried back out to sea by surface currents, down to the anoxic bottom waters where deposition of the black shale would have occurred. According to Parrish (1982, p. 766) the Bakken sea was not located in an ideal paleogeographic position for upwelling to occur, but moderate upwelling might still be a possiblity.

Another possible environment includes "shallow" (less than 100? feet) marine or marginal-marine waters. In this case, a physical barrier to restrict epeiric sea circulation is not necessary to cause

anoxic water conditions. Prolific organic growth (mainly algae) resulting in a vegetal flotant, could restrict the sea's normal circulation, as proposed by McCabe (1959). Below the vegetal flotant the bottom waters would have been stagnant and anoxic. Heckel (1977) states that black shale deposited under these conditions would have to be in very shallow water and should display abrupt lateral facies changes into other shoreline and shallow-water deposits (e.g. sandstones and other rock types associated with channels, minor beachlets, and tidal flats). These abrupt lateral facies changes are not present in the Bakken shales.

Further research on the paleogeography and paleoecology of the Bakken Formation is needed before a definitive statement on the depositional environment of the Bakken shales can be made. In the author's opinion the Bakken shales were probably deposited in an offshore, marine environment with water depths less than 200 feet. Silling of the basin or the establishment of upwelling currents could have caused the anoxic water conditions.

Petroleum Geology

The Bakken Formation is a significant oil-producing interval in North Dakota. A total of 4,657,870 barrels of oil have been produced from the Bakken within the study area as of October, 1981. Production has been established from the Bakken in nine North Dakota oil fields (Fig. 16) with the Antelope Field in eastern McKenzie County the most prolific producer of Bakken oil. The Antelope Field accounts for 89 percent of the total Bakken production in the study area. The Bakken produces from approximately 30 wells in this field,

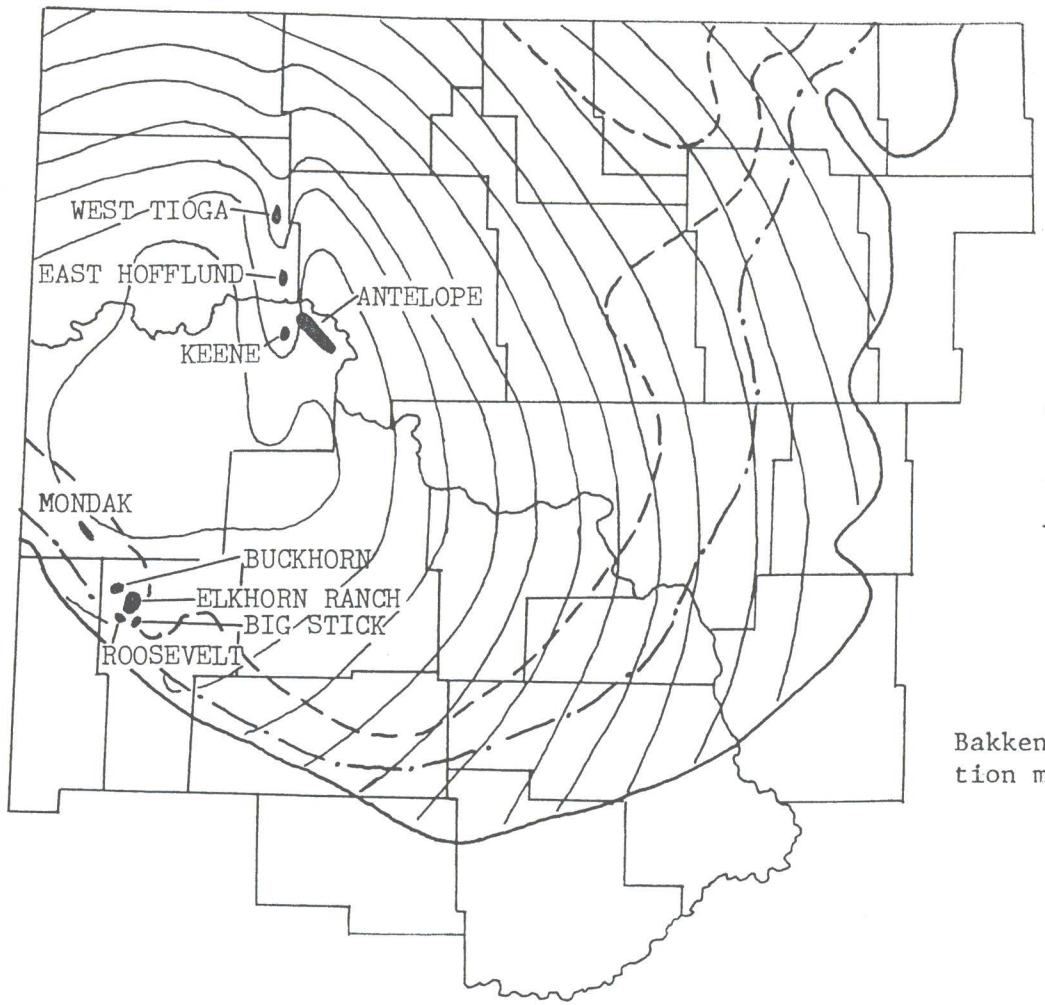


Fig. 16. Location and name of Bakken oil fields with superimposed formation member limits and structure contours.

and is usually perforated in the middle member and part of the lower shale member. The underlying "Sanish Sand" interval is usually perforated along with the Bakken in this field. In other Bakken oil fields, the location of perforations varies; in some wells all three members are perforated. Murray (1968) noted that production in the Antelope Field does not vary with reservoir lithology, so that similar rates of production were established in wells where only the "Sanish" was perforated or in wells where only the Bakken was perforated. No attempt has been made to separate the production by zones and consequently the direct contribution of the Bakken shales to oil production is unknown. Likewise, in the Antelope Field it is unknown how much of the "Bakken" production actually originates from the upper Three Forks in the "Sanish Sand" interval.

The reservoir properties of the Bakken are generally very poor in the area studied. Core analyses from the NDGS well files reveal the middle member to have porosities in the range of 1 to 6 percent, and permeability less than 0.1 md. The adjacent rock units of the Three Forks and Lodgepole display very similar porosity and permeability and can be considered marginal reservoir rocks. Fracturing, which renders the rock permeable, is believed by several workers (Murray, 1968; Finch, 1969; Meissner, 1978) to be the factor responsible for oil production from the marginal reservoir rocks of the Bakken.

Shows of oil and gas in the Bakken are very common in the deep portion of the Williston basin, yet drill stem tests of most of the shows recover only gas- and oil-cut mud and have low, unstabilized shut-in pressures (Meissner, 1978). Little water is recovered in Bakken drill stem tests, or produced from Bakken oil fields until advanced

stages of depletion. This fact led Meissner (1978) to suggest that hydrocarbons are the only movable fluid found in the Bakken in the deep portions of the basin.

To account for the seemingly impossible initial rates of production from the very "tight" Bakken and "Sanish" lithologies in Antelope Field (an average of nearly 200 BOPD), Murray (1968) concluded that fracturing was directly related to oil production in the Sanish pool of the Antelope Field. Murray believed the type of fracturing present at Antelope is a tension-fracture system and is best developed in areas of greatest structural curvature on the Antelope anticlinal structure. Figure 17 is a structure contour map on top of the Bakken at Antelope Field which illustrates the degree of curvature of the Bakken as calculated by Murray (1968). The best oil wells are seen to be associated with the areas of greatest curvature and, according to Murray, the areas of better-developed fracturing. Oil production is low to nonexistent on the crest of the anticline where normally the best production or accumulation of oil would be expected.

The Bakken was observed by Murray (1968), Finch (1969), and Meissner (1978) to be anomalously overpressured at Antelope (Fig. 18) and throughout much of the deep basin by Meissner (1978, p. 217). Meissner attributed this overpressuring to hydrocarbon generation in the Bakken shales which would result in excess volumes of oil in the shale pore spaces. This anomalous overpressure was believed by Meissner to be maintained by the isolation of the Bakken by very impermeable rocks of the Three Forks and Lodgepole, thus hindering the expulsion of the excess fluid.

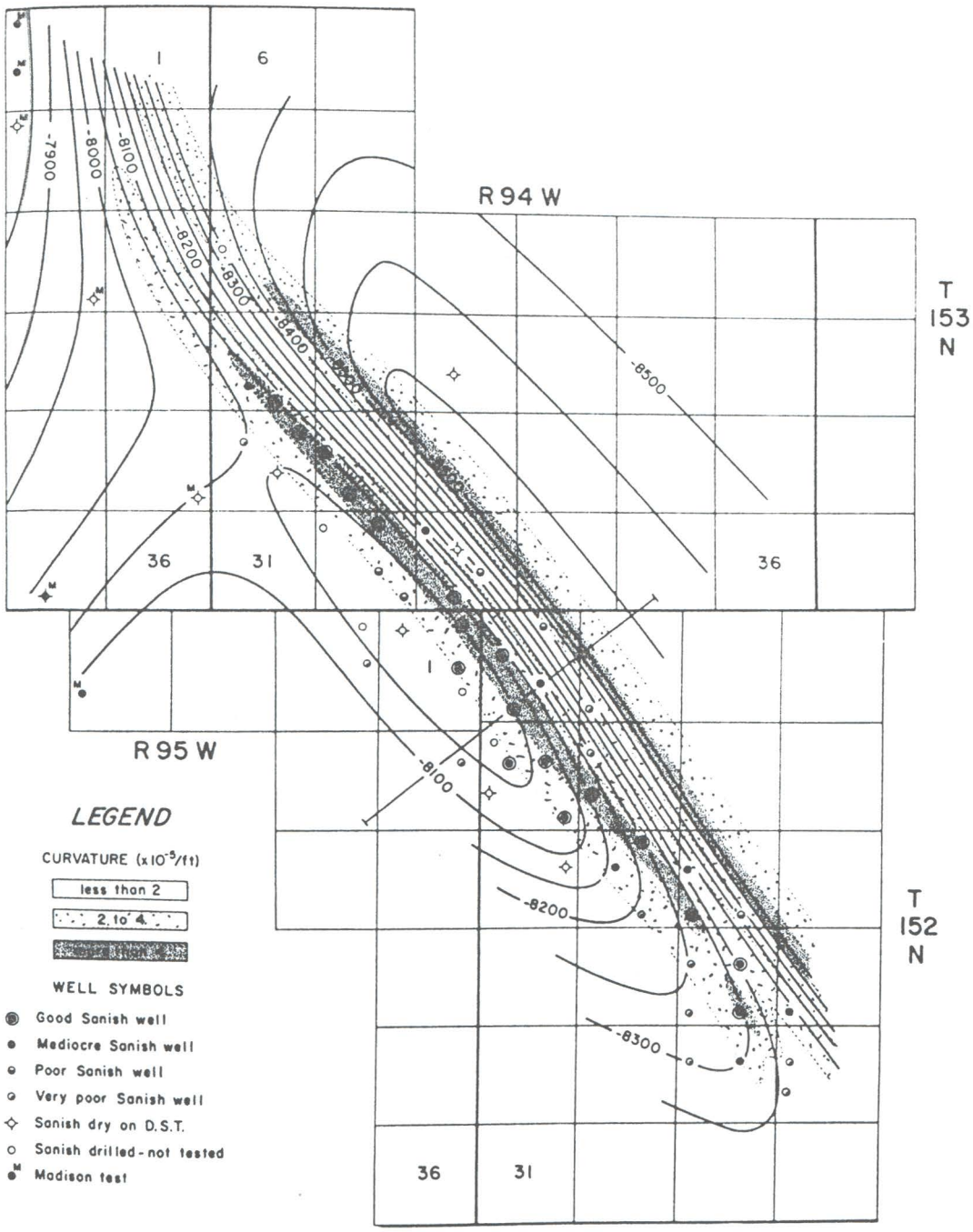


Fig. 17. Structural contour map of Antelope Sanish pool, on top of the Bakken Formation. As noted on legend, well spots are keyed to their productivity and values of structural curvature are mapped by patterned areas. Contour interval is 50 feet and datum is sea level (Modified from Murray, 1968, p. 63).

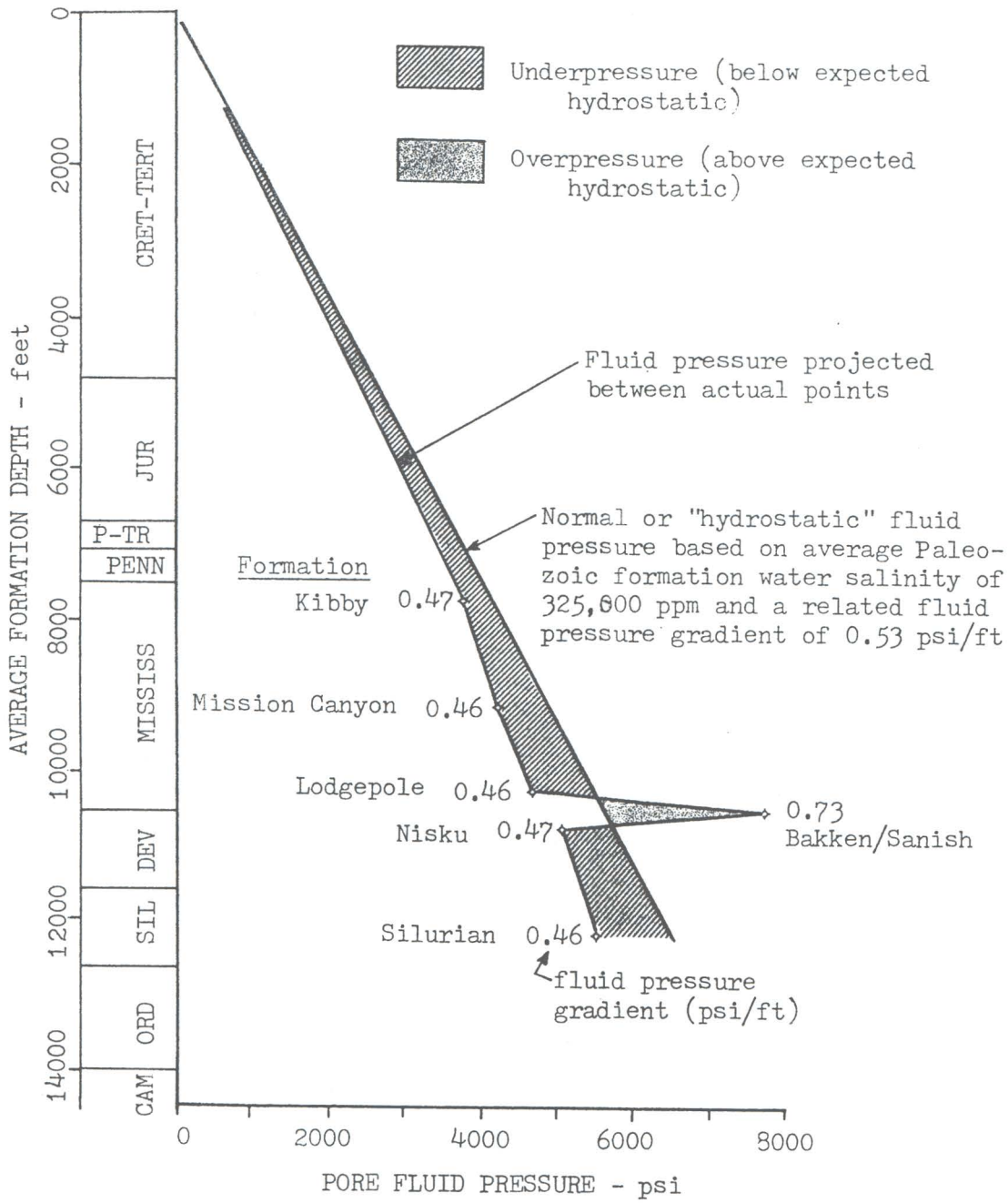


Fig. 18. Reservoir fluid pressure versus depth for Antelope Field, McKenzie County, North Dakota (Modified from Meissner, 1978, p. 211).

SOURCE ROCK EVALUATION

Organic matter in fine-grained rocks can be divided into several main components as seen in Figure 19. The majority of the total rock is made up of inorganic mineral matter with organic material generally composing a very minor amount of the rock. Of the total organic matter, most is kerogen (insoluble in organic solvents) and a lesser amount is bitumen (soluble in organic solvents). The bitumen can be broken down into two main fractions using chromatography: the high molecular weight compounds (resins and asphaltenes) and the hydrocarbon compounds. Hydrocarbons are then further subdivided into aromatic hydrocarbons and saturated hydrocarbons.

As a petroleum source rock is buried and subjected to higher subsurface temperatures, its bitumen composition changes. This change can be attributed to the thermal breakdown of kerogen into hydrocarbons and other nonhydrocarbon organic molecules forming new bitumen. Oil generation is the result of thermal breakdown of kerogen material in the source rock. Tissot and Welte (1978, p. 185) present a generalized scheme for hydrocarbon formation in a source rock as a function of burial depth (Fig. 20). As seen on this diagram, the three main stages of organic matter alteration are diagenesis, catagenesis, and metagenesis. In regard to organic matter, diagenesis involves the breakdown or changing of organic material primarily by biologic means. Some biogenic methane is produced during this stage, but the bitumen from a source rock in this stage would be composed mostly of indigenous organic material

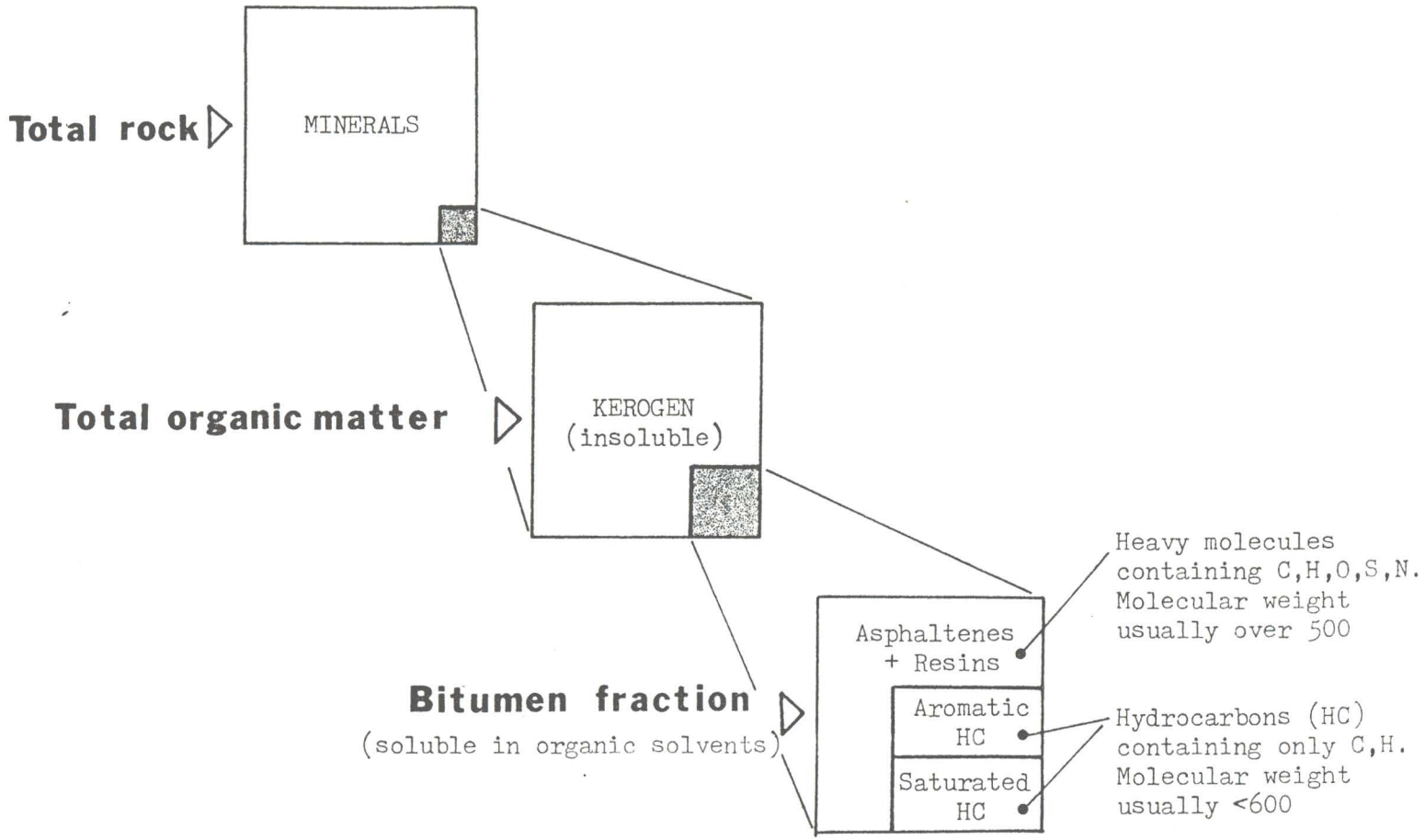


Fig. 19. Composition of disseminated organic matter in ancient sedimentary rocks (Modified from Tissot and Welte, 1978, p. 124).

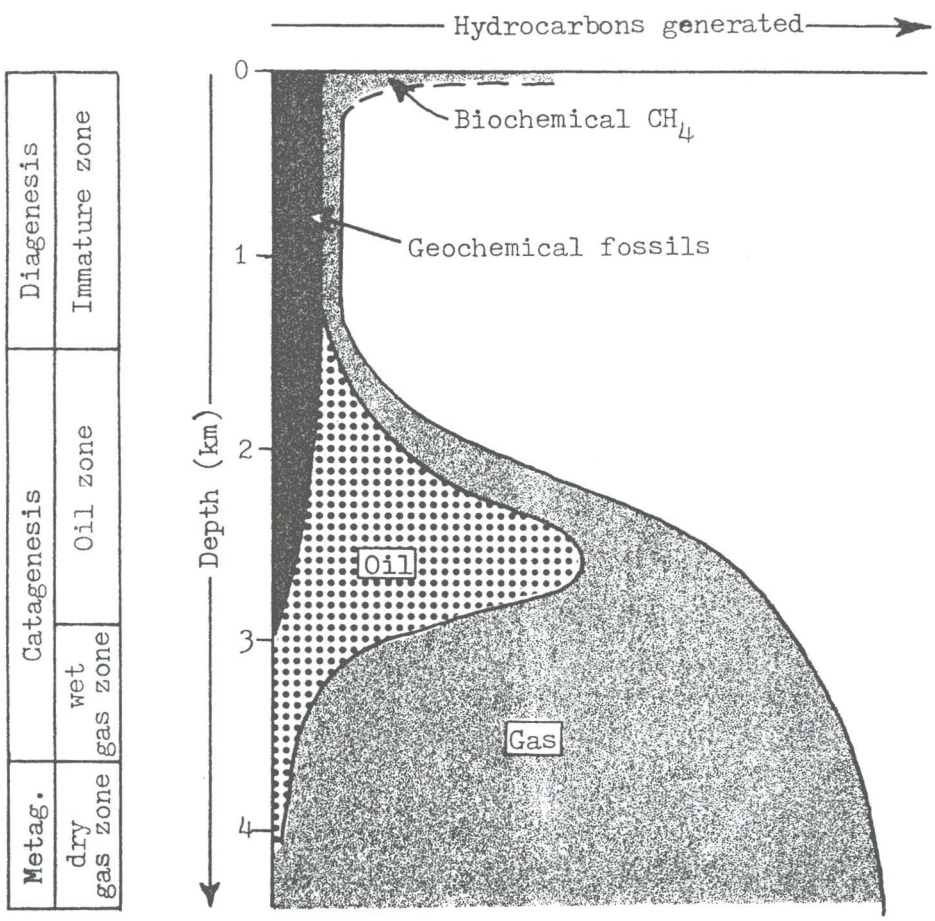


Fig. 20. General scheme of hydrocarbon formation as a function of burial of the source rock. Depths are only approximate and correspond to an average of values from Mesozoic and Paleozoic rocks. Actual depths vary according to the particular geological conditions: type of kerogen, burial history, geothermal gradient. Modified from Tissot and Welte (1978, p. 185).

(mostly resins and asphalteness) which Tissot and Welte term "geochemical fossils". Catagenesis is the principal zone of oil generation. Thermal breakdown of kerogen is the main alteration which takes place in this stage, and this results in a much higher hydrocarbon content in the source rock. Metagenesis is the final stage, where temperatures are much higher and oil generation is essentially complete. Kerogen is further broken down in this stage to form methane and other dry gases. Further details of source maturation can be found in Tissot and Welte (1978), Hunt (1979), and Waples (1981).

To evaluate the Bakken shale as a petroleum source rock, it is necessary to know how the organic geochemistry of the shale varies within the study area. Organic geochemical analyses of the Bakken shales were performed in two different geochemical laboratories: the U.S. Geological Survey Laboratory in Denver, Colorado, and the Conoco Exploration Research Laboratory in Ponca City, Oklahoma.

Organic geochemical analyses made for this study include the following:

1. Total organic carbon measurements
2. Extraction of soluble organic material and analysis of this material by thin layer chromatography
3. Pyrolysis
4. Vitrinite reflectance
5. Visual kerogen typing

Conoco performed organic carbon measurements, extraction of soluble organics, thin layer chromatography, vitrinite reflectance, and visual kerogen typing. The U.S. Geological Survey performed pyrolysis and additional organic carbon measurements. These analyses and their uses

will be explained in following sections.

Sampling

Samples of the Bakken shales were obtained from cores and cuttings stored in the Wilson M. Laird Core and Sample Library of the North Dakota Geological Survey in Grand Forks. Locations of samples for which geochemical analyses were made, and the type of sample used, are depicted in Plate 3.

In the case of core samples, composite samples were made by taking a small chip from the center of the core at intervals of approximately 6 inches to 1 foot. These chips were then combined to form a composite sample for the interval of Bakken shale cored. Approximately 15 to 20 grams of shale were required, for a single sample, to perform all geochemical analyses. Certain analyses performed alone, such as pyrolysis, required much less sample.

In order to obtain an adequate geographic and depth distribution of geochemical samples, well cuttings were utilized in areas where cores were not present (Plate 3). Sampling of well cuttings involved placing the cuttings for a 5 to 10 foot depth interval under a binocular microscope and wetting them with water. Picking of Bakken shale from the well cuttings was more easily done when they were water-wet, as the Bakken chips could be differentiated from other dark colored shales based on their dark black color and hardness. If a sufficient amount of Bakken shale was present in the cuttings samples, then geochemical samples for both the upper and lower shale were obtained; but in the case of insufficient amounts, cuttings of both shales (if present) were mixed to form a composite sample for the particular well. Wells

used for samples are listed in Appendix D by their NDGS number with sample type and the formation member sampled.

The samples from cores and cuttings were then sent to the respective laboratories where they were prepared for geochemical analyses.

Explanation of Organic Geochemical Methods Used

Total Organic Carbon Measurements

Organic carbon is a measure of the total organic matter (kerogen and bitumen) preserved in the rock, expressed as weight percent of the rock. This measurement is obtained by high-temperature combustion of the organic carbon in a weighed sample of rock after inorganic carbon has been removed by acid treatment. The weight percent of organic carbon is calculated from the amount of carbon dioxide generated by the combustion of the organic matter. Organic carbon values in this study are listed in Appendix E and F.

Extraction of soluble organics

To remove soluble organic matter from the rock, a large portion of the ground rock sample was placed in a Soxhlet extractor (Fig. 21) which continually circulates an organic solvent through the rock sample to dissolve out the bitumen in the rock. The organic solvent used in this case was a mixture of toluene and isopropyl alcohol. After a 12 hour period of extraction the solvent containing the dissolved bitumen was air dried at room temperature, leaving the $C_{15}+$ organic compounds as a residue.

This residue was separated, using thin layer chromatography,

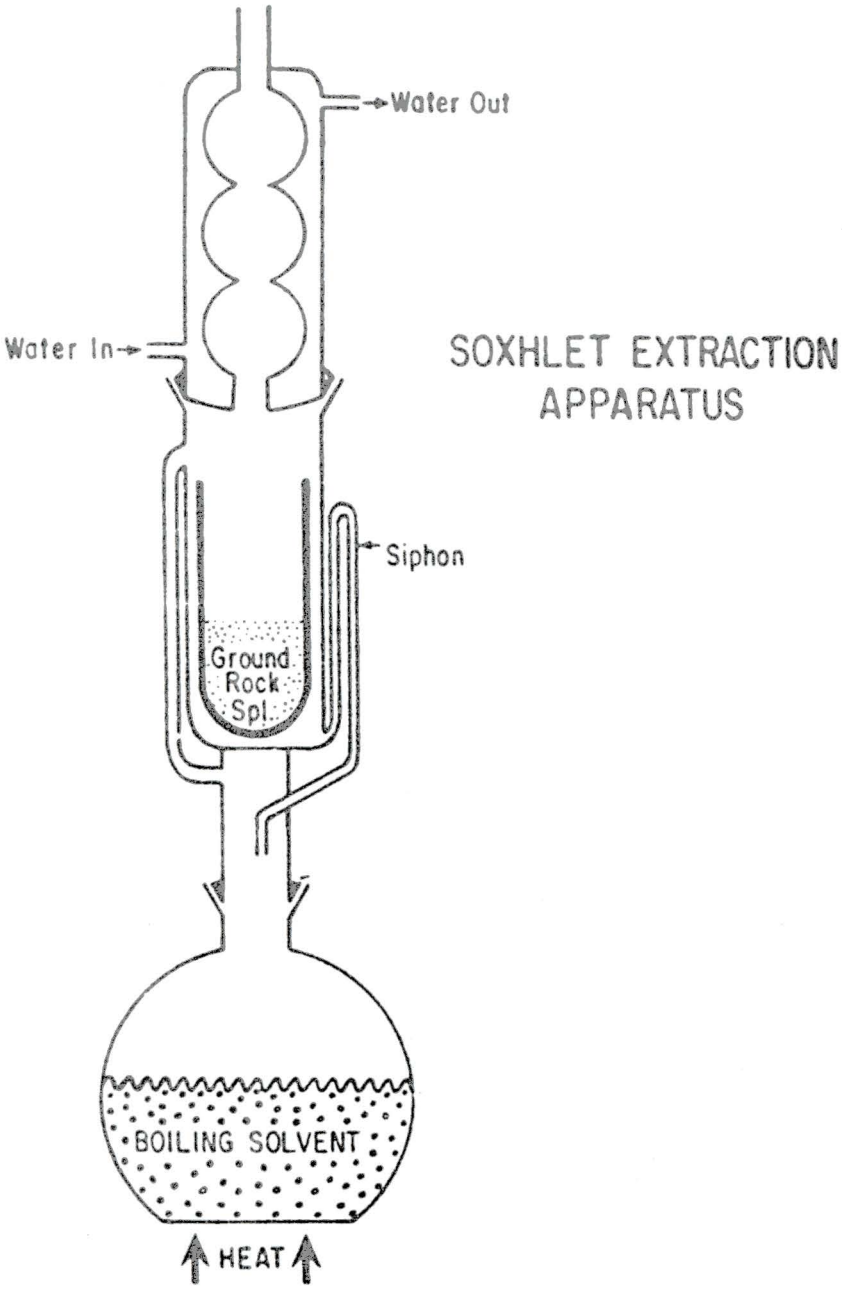


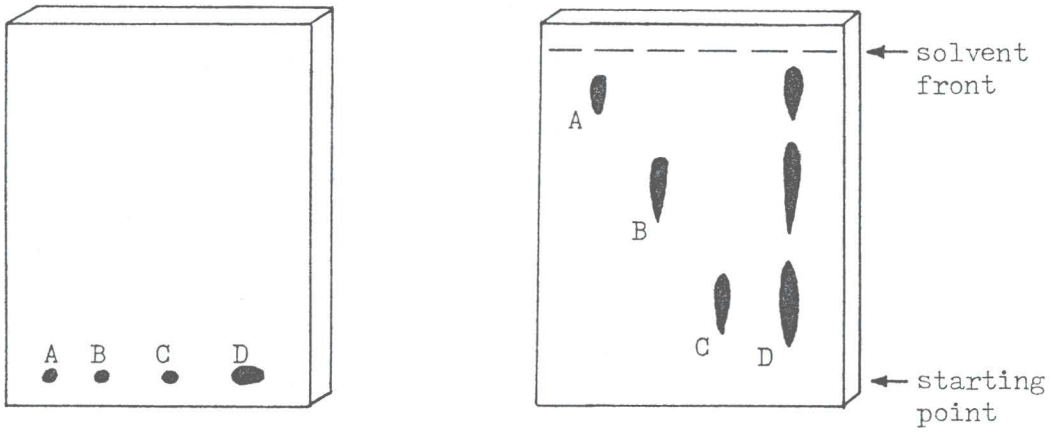
Fig. 21. Soxhlet extraction apparatus used to extract soluble organic matter from rock.

into three fractions of compounds: saturated hydrocarbons, aromatic hydrocarbons, and resins and asphaltenes (grouped together). Small portions of the extract were placed a short distance from the bottom of a glass plate coated with a thin layer of silica gel. The plate was then placed upright in a tank where solvent just covered the lower edge. The solvent moves up the plate and through the silica gel by capillary action, carrying the organic compounds with it. The rate of travel of the different types of organic compounds in the solvent depends on their solubility in the solvent. The saturated hydrocarbons are the most soluble and travel the farthest up the plate, followed by the aromatic hydrocarbons and then the resins and asphaltenes (Fig. 22). The plates were then "developed" by burning the organics with H_2SO_4 vapors, leaving a carbon char which fixes the area of each compound. These areas were measured with an optical densiometer, and the percent concentration of compound types was computed by the laboratory workers. Results of the thin layer chromatography are listed in Appendix E.

Pyrolysis

Pyrolysis involves heating a whole rock sample to increasing temperatures while passing an inert gas over the sample and into a detector which is sensitive to combustible material. Relative amounts of volatile organics (bitumen) are recorded in graphic form on a thermogram which plots detector response against temperature (Fig. 23). Generally two peaks separated by a saddle are obtained on the thermogram. The area of the first peak is referred to as S_1 and it is related to the Soxhlet-extractable hydrocarbon content of the source rock. The area of the second peak is referred to as S_2 and it is

THIN LAYER CHROMATOGRAPHY



A = sample of saturated hydrocarbons
B = sample of aromatic hydrocarbons
C = sample of resin and asphaltene compounds
D = sample of A+B+C combined

Fig. 22. Diagram illustrating thin layer chromatography operation. Three fractions of soluble organic material are obtained by separation by movement in a solvent through a thin layer of silica gel.

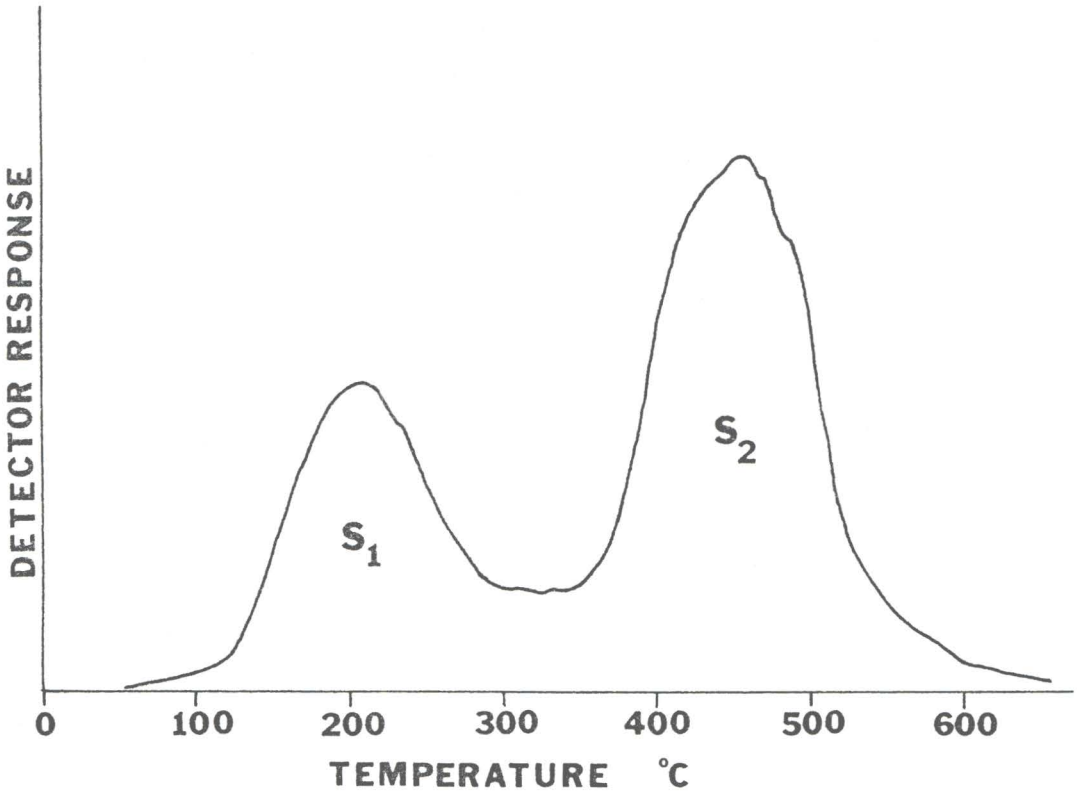


Fig. 23. Example of a possible thermogram obtained by pyrolysis of a source rock sample. The left hand peak (S_1) represents the solvent extractable hydrocarbons and the right hand peak (S_2) represents the hydrocarbons pyrolyzed from the kerogen.

related to the amount of pyrolyzable hydrocarbons attached to the kerogen or the hydrocarbon-generating potential of the kerogen (Claypool and Reed, 1976, p. 610). Details of the analytical conditions and results of the thermal analyses are given in Appendix F.

Visual Kerogen Typing

In order to identify the type of kerogen in the ground rock sample, a kerogen isolation must be performed. This is done by treating the sample with HCL and HF acid for 12 hours respectively and then rinsing with water twice after HCL treatment and six times after HF treatment. These acids remove a great deal of the mineral matter in the sample, leaving kerogen and acid-resistant minerals such as pyrite, as a residue. This mixture is considered satisfactory for visual kerogen typing.

Kerogen typing involves placing a portion of the kerogen isolate on a glass microscope slide and mounting it in a clear medium. The slide is viewed under a microscope and kerogen types are identified from their morphology. The Conoco laboratory workers used the standard nomenclature developed by palynologists in the petroleum industry (Hunt, 1979, p. 276) which recognizes five main kerogen types; algal, amorphous, herbaceous, woody, and coaly. A visual estimate of each type of kerogen present was made for each sample. The results of the kerogen typing are given in Appendix G.

Vitrinite Reflectance

Vitrinite is a type of kerogen particle that is derived from higher land plants and is made up of the humified remains of the lignin and cellulose of cell walls (Dow, 1977). This type of particle is used

as a thermal maturity indicator by measuring the percentage of light that can be reflected from it. The greater the degree of thermal maturity, the greater the reflectance.

Heavy liquid (zinc bromide, density = 2.5 g/cc) separation was used to remove the very fine-grained amorphous kerogen particles from the kerogen isolate before it was used for vitrinite reflectance. Small portions of the separated kerogen isolate were mounted in plastic plugs and polished. Reflectance measurements were made, under a specially adapted microscope, on as many vitrinite particles in one sample as possible, generally between 40 and 60. A computer then plotted the data as a histogram and recorded the mean and standard deviation. The values obtained for this study are listed in Appendix H.

Results of Organic Geochemistry

Organic Carbon Measurements

The Bakken shales have high values of organic carbon; these values range from 5 to 20 percent by weight, with an average of 11.33 percent. These values are considered to be very high, as the minimum organic carbon value for a possible source rock in the Rocky Mountain region is considered to be about one percent (Merewether and Claypool, 1980, p. 493).

Figures 24 and 25 display the map distribution of organic carbon in the upper and lower shales respectively. Both shales have high organic matter contents throughout their extent, with a slightly lower organic content occurring in some areas near the depositional limits.

Examples of vertical distribution of organic matter in the

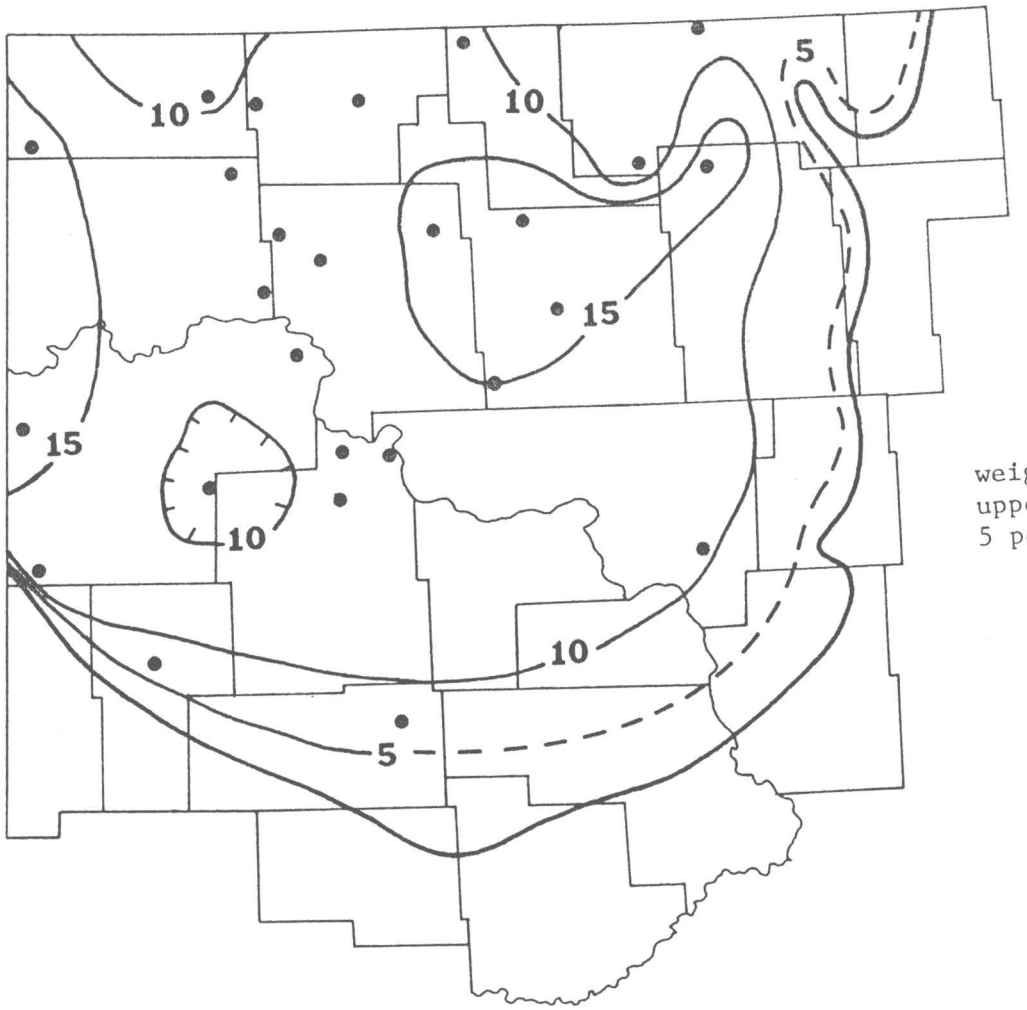


Fig. 24. Contour map of weight percent organic carbon of upper shale. Contour interval is 5 percent.

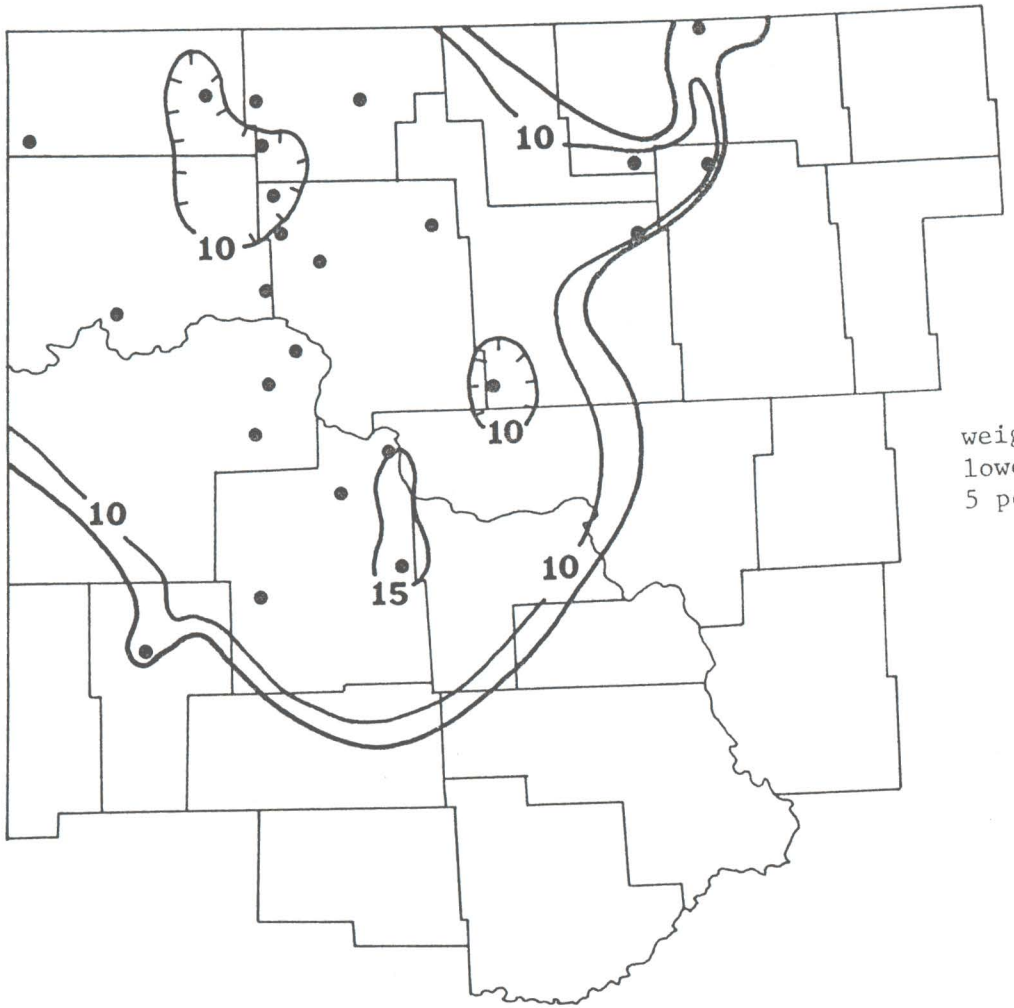


Fig. 25. Contour map of weight percent organic carbon of lower shale. Contour interval is 5 percent.

Bakken shales are illustrated in Figure 26. From the two wells that were sampled in detail, it can be seen that significant vertical variations in organic content occur. This could affect the reliability of organic carbon values obtained from composite samples, as it would be possible to resample the same interval and come up with a different organic carbon value. Consequently the maps of organic carbon in the Bakken shales should be taken only as approximations.

Kerogen Typing

Kerogen of the Bakken shales is predominantly (70 to 95 percent) amorphous (Fig. 27a). Recently it has been demonstrated (Powell et al., 1982) that amorphous organic matter can originate from algal, terrestrial, or microbially degraded organic material. It seems likely the amorphous Bakken kerogen has an algal origin, as the hydrocarbon-generating capacity of this material determined from pyrolysis is quite high (greater than 500 mgHC/gOC at shallow depths) and indicates a high atomic hydrogen to carbon ratio for the kerogen. Amorphous kerogen with high H/C ratios can be termed sapropelic. Sapropelic refers to organic matter that originated from fatty, lipid organic materials such as spores and planktonic algae deposited in subaquatic muds (marine or lacustrine), usually under oxygen-restricted conditions (Hunt, 1979, p. 273).

Minor amounts of other kerogen types were found by the operators at Conoco. Herbaceous kerogen (derived mostly from continental plant material) ranged from 0 to 20 percent. Woody kerogen, which is fibril material with recognizable rectangular structures and exclusively terrestrial, was almost nonexistent. It occurred in only 5 samples in

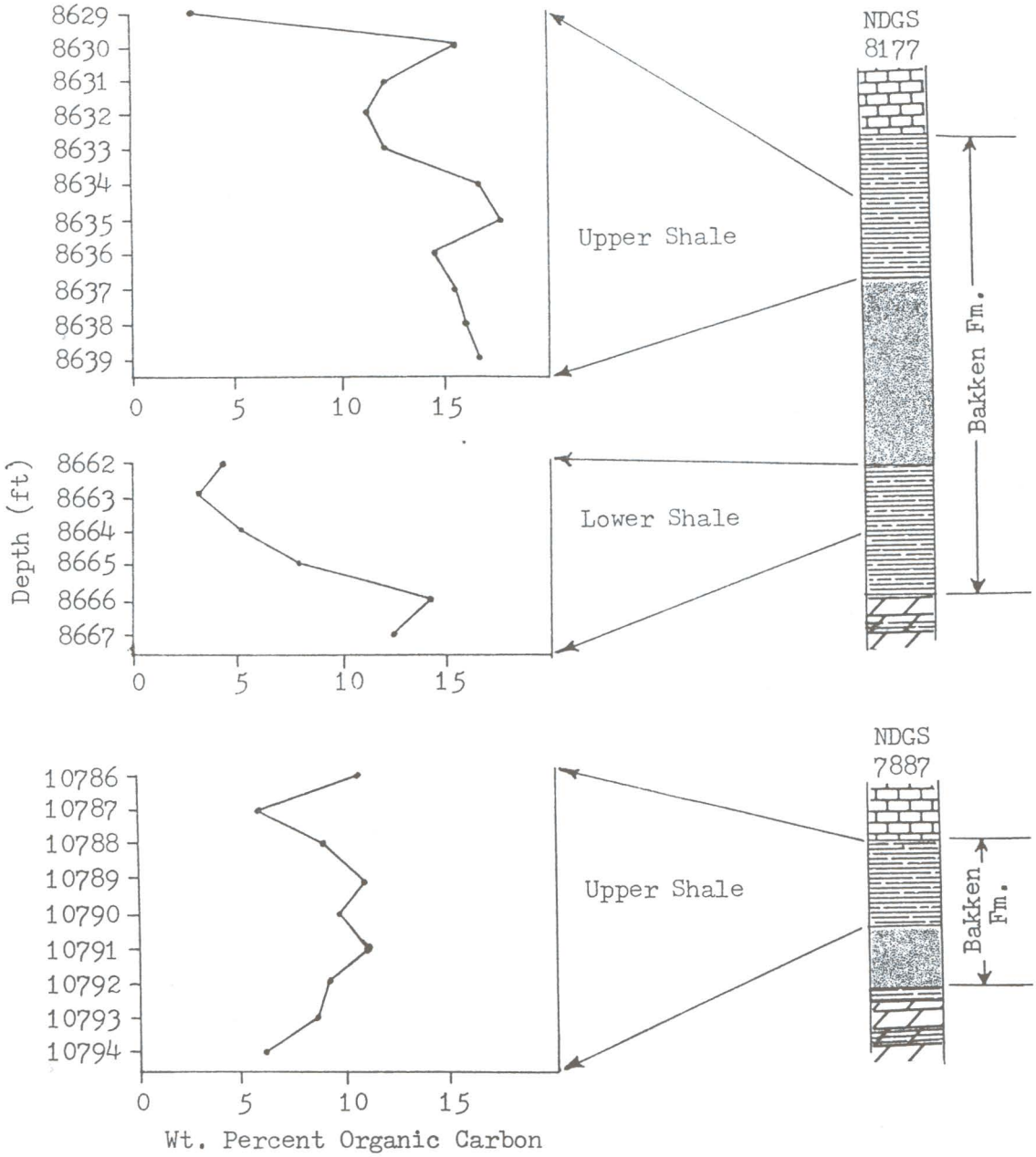
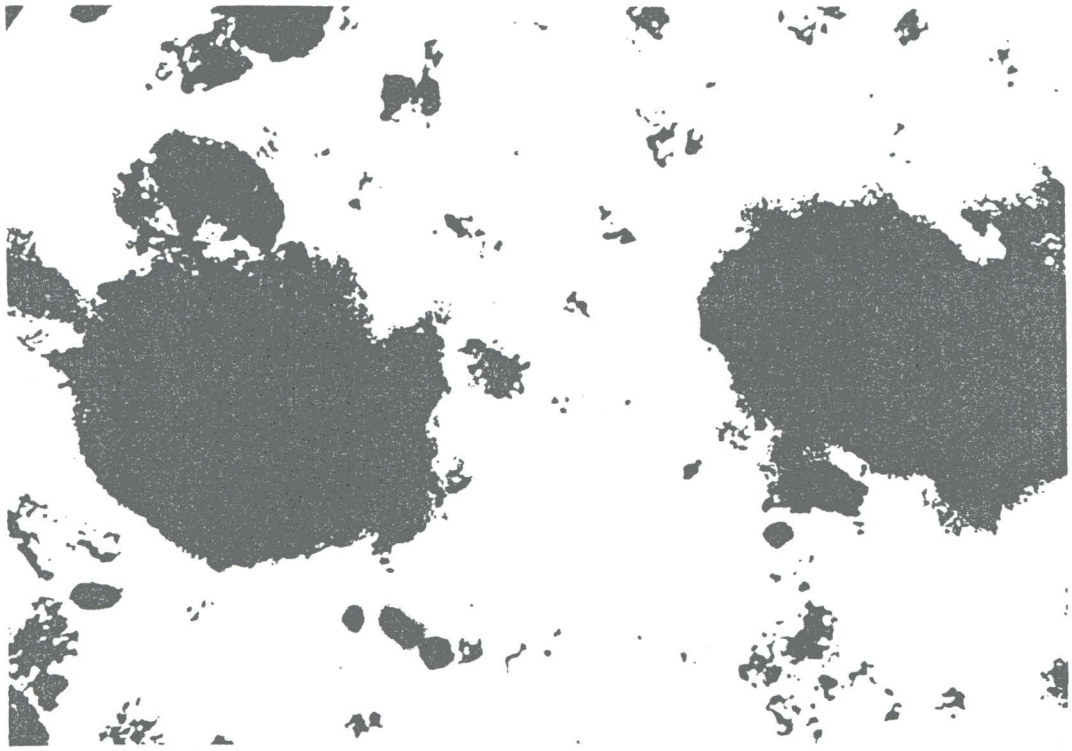


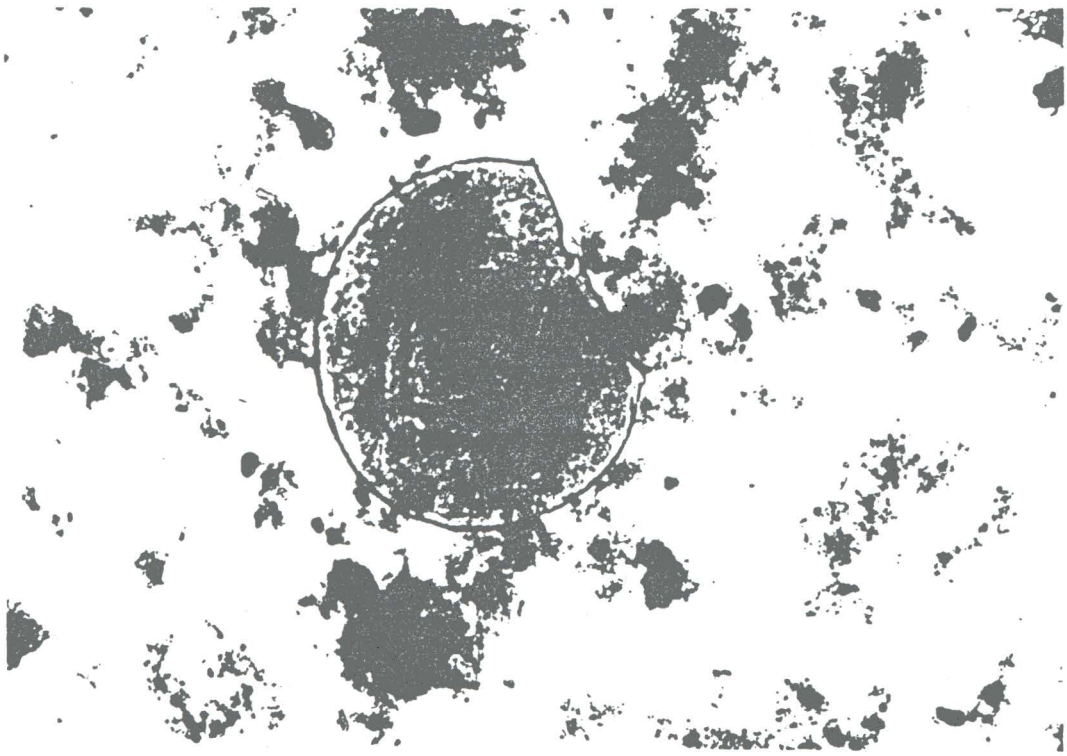
Fig. 26. Vertical distribution of organic matter in three Bakken shale sections, from NDGS well no. 8177 in southwestern Ward County, and NDGS well no. 7887 in central Billings County.

Fig. 27. Photomicrographs of kerogen isolate material of the Bakken shale.

A. Photomicrograph of amorphous kerogen in the upper shale of NDGS well no. 105. Plane polarized light with a magnification of 250X.

B. Photomicrograph of a tasmanite spore in the lower shale of NDGS well no. 4508. Plane polarized light with a magnification of 100X.





amounts of 5 percent or less. Coaly kerogen (recycled opaque organic material) occurred in amounts of 30 percent or less. The confidence factor, a relative assessment of the reliability of the kerogen typing data, was fair to poor for all the samples examined by the laboratory workers at Conoco.

Tasmanite spores were identified in some of the kerogen samples examined (Fig. 27b). This spore type is thought to be equivalent to the present day unicellular marine alga Pachysphaera pelagica (Wall, 1962). The presence of this spore type in the Bakken shales is consistent with the postulated marine sapropelic origin of Bakken organic matter. Tasmanites are also recognizable in thin sections of the Bakken shales. They are often compressed into discs and replaced partially by pyrite. Tasmanites are also visible to the naked eye in cores of the Bakken shales and can be quite abundant locally.

Extractable Organic Matter

Solvent-extractable organic matter in the Bakken shales ranges between 2,100 and 15,400 ppm of the rock and doesn't exhibit any clear trend with increasing depth. Samples from shallow depths (3,000-4,000 feet) often had total bitumen contents as high as those obtained from deep (greater than 9,000 feet) samples. However, there is a drastic difference in the composition of bitumen from shallow samples and bitumen from deep samples. Shallow bitumen is composed mostly of resins and asphaltenes, whereas the deep basin bitumen is composed of 40 to 70 percent hydrocarbons.

Breakdown of bitumen by thin layer chromatography into saturated

hydrocarbons, aromatic hydrocarbons, and the combination of resins and asphaltenes, makes it possible to observe changes in the amount of these components and ratios of the various components with depth.

Maps and graphs made from these data were used to interpret the stages of oil generation in the Bakken shales. Hydrocarbon data from the upper and lower shales were averaged together for map points where both of the shales were sampled separately. Curves drawn on graphs plotting geochemical parameters against depth have been fitted visually. Depths used are present-day burial depths acquired directly from well logs; no attempt was made to adjust these depths to a possible maximum burial depth of the past, as there is no evidence to suggest that these depths were significantly greater in the past, in the author's opinion.

Hydrocarbons extracted from the Bakken shales greatly increase in concentration in the deeper parts of the basin. The ratio of hydrocarbons to nonhydrocarbons in the $C_{15}+$ extracts increases slightly with increasing depth at first and then shows significant increase below 9,000 feet (Fig. 28). The first break in the curve on this graph, where hydrocarbon content begins to increase significantly (about 9,000 feet), is interpreted to represent the onset of hydrocarbon generation in the shales. The large increase in hydrocarbons that occurs in samples from greater than 10,000 feet is interpreted to represent the stage of peak or intense generation. This graph (Fig. 28) represents the upper half of the oil peak in Figure 20, as the Bakken has not reached completion of oil generation. The map distribution of the HC/nonHC ratio (Fig. 29) shows a general increase towards the basin deep.

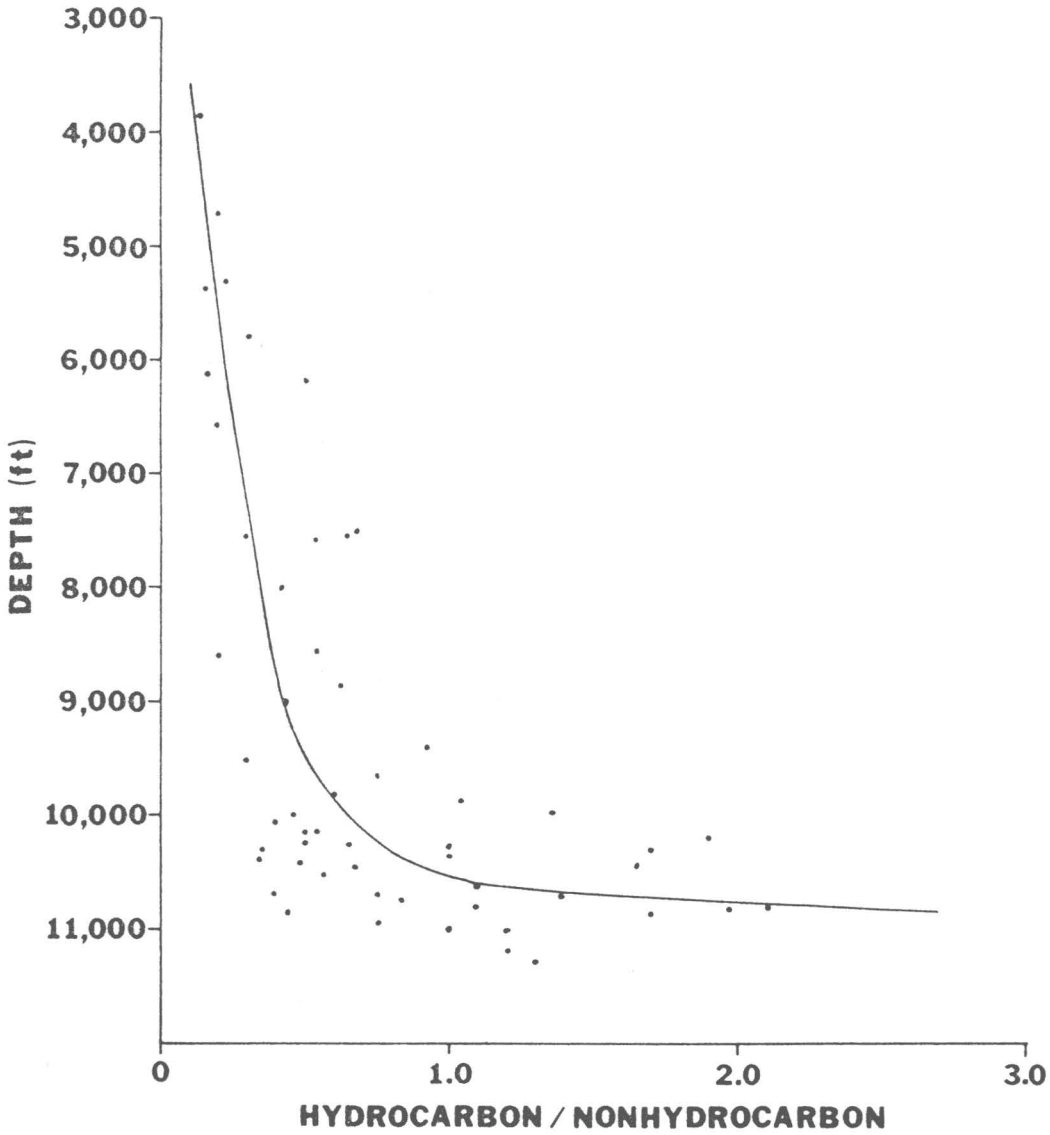


Fig. 28. Ratio of C_{15}^{+} hydrocarbons to nonhydrocarbons versus depth for the Bakken shale.

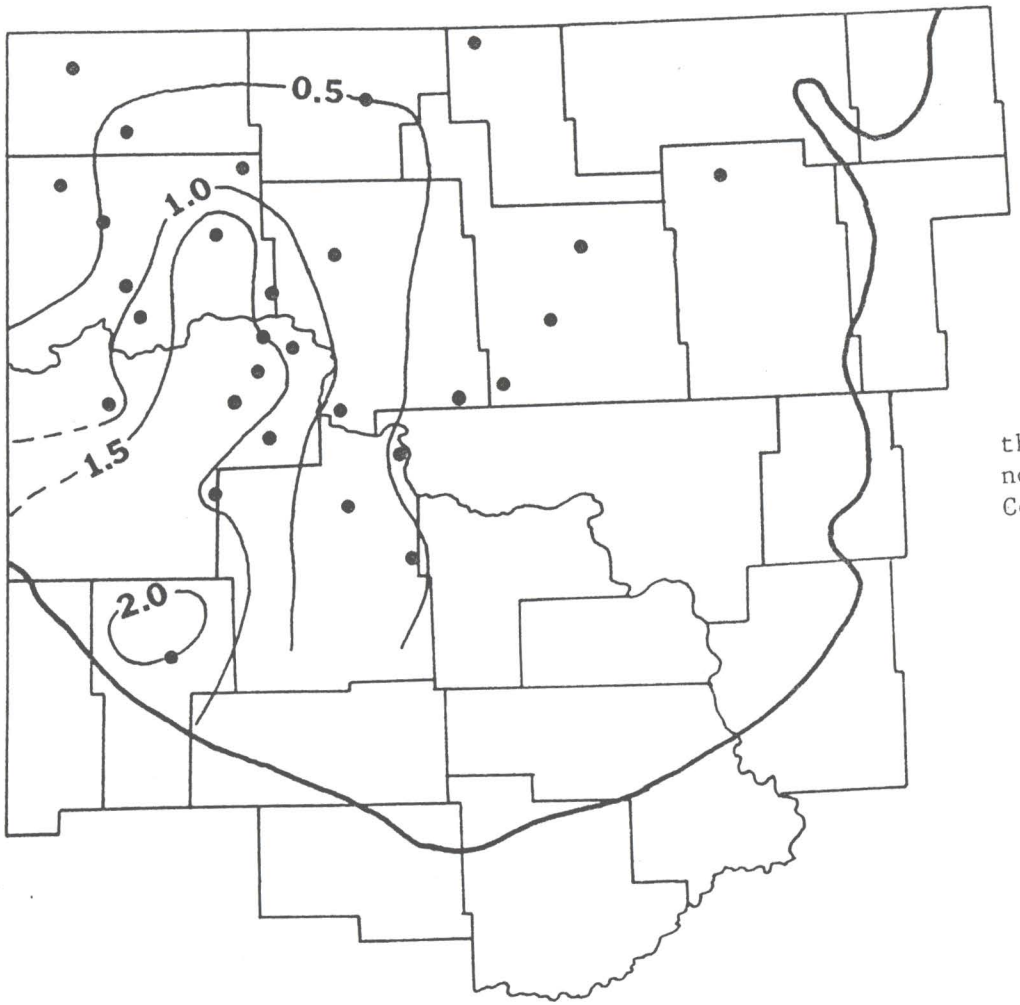


Fig. 29. Contour map of the ratio of C_{15} + hydrocarbons to nonhydrocarbons for the Bakken shale. Contour interval is 0.5.

Primary migration of hydrocarbons could have affected the hydrocarbon data used in this study by causing depletion or enhancement of the indigenous hydrocarbon content of the shales. The moderately strong grouping of points that have ratios less than 1 and are at depths of 10,000 feet or greater (Fig. 28) may represent the effects of primary migration of hydrocarbons from the Bakken shales resulting in lower hydrocarbon contents than would be expected for these deep samples. Other possible explanations for these "anomalous" values are lack of hydrocarbon generation or poor samples that have lost part of their indigenous hydrocarbon content in some way.

A useful organic geochemical parameter that is often used to evaluate maturity in source rocks is the ratio of hydrocarbon to organic carbon. When plotted against depth, this parameter does not have a well-defined trend for the Bakken shales (Fig. 30). A general increase with increasing depth can be vaguely seen, but there is considerable scatter below 7,000 feet. One possible explanation for the scatter of data points is primary migration of hydrocarbons affecting the indigenous hydrocarbon content by increasing or deleting it. Other possibilities are partial loss of indigenous hydrocarbons in the sample, contamination of the sample by oily substances in the drilling mud, or analytical error in the thin layer chromatography. When the hydrocarbon fraction is separated into its two components, aromatics and saturates, and their changes with depth are observed separately (Figs. 31, 32), it can be seen that most of the scatter in the HC/OC ratio is due to the aromatics. It is possible that other aromatic compounds containing NSO heteroatoms may be present in the aromatic hydrocarbon fraction, thus this fraction may not represent aromatic

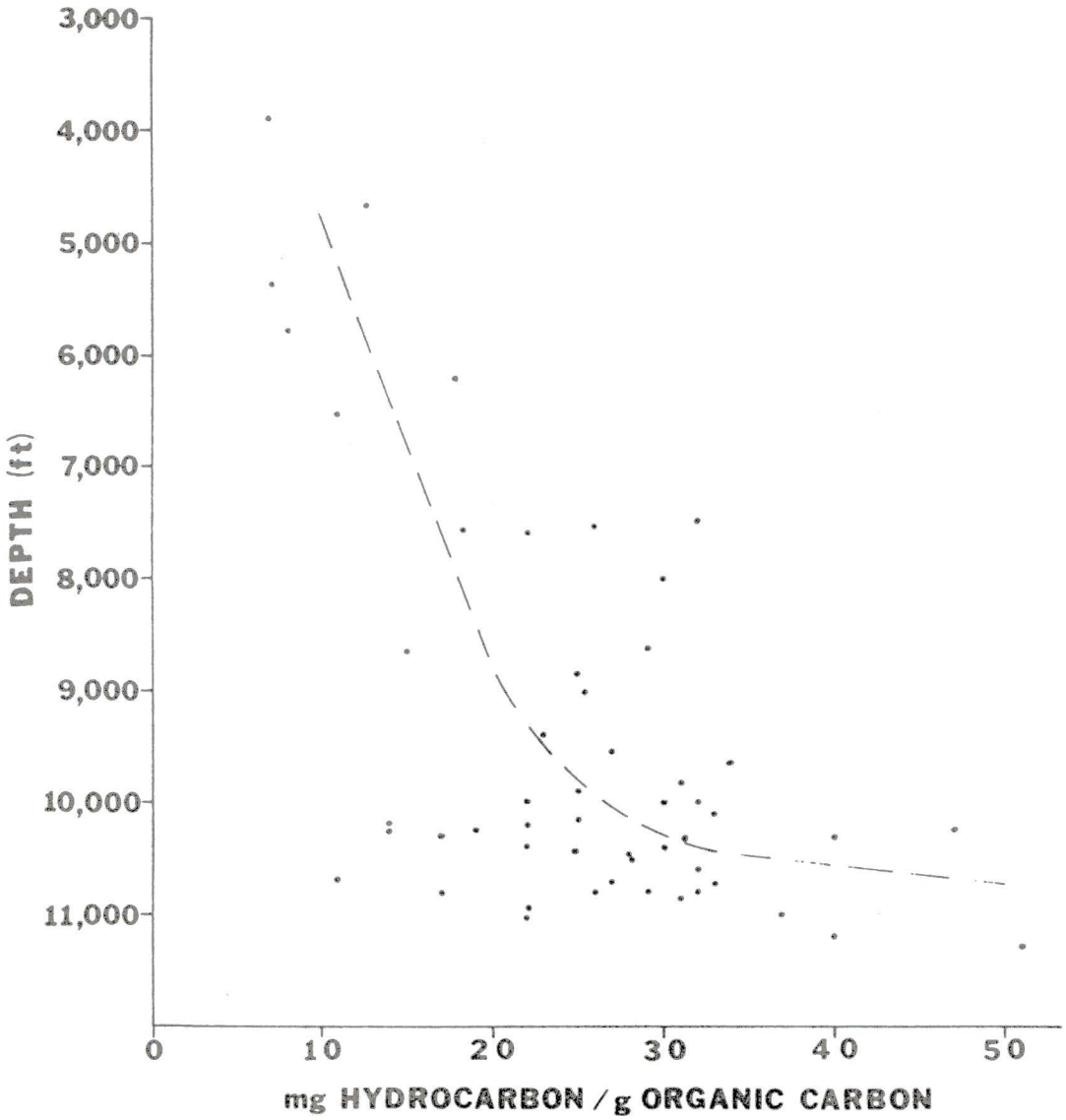


Fig. 30. Ratio of C_{15+} hydrocarbons to organic carbon (mg/g) versus depth for the Bakken shale.

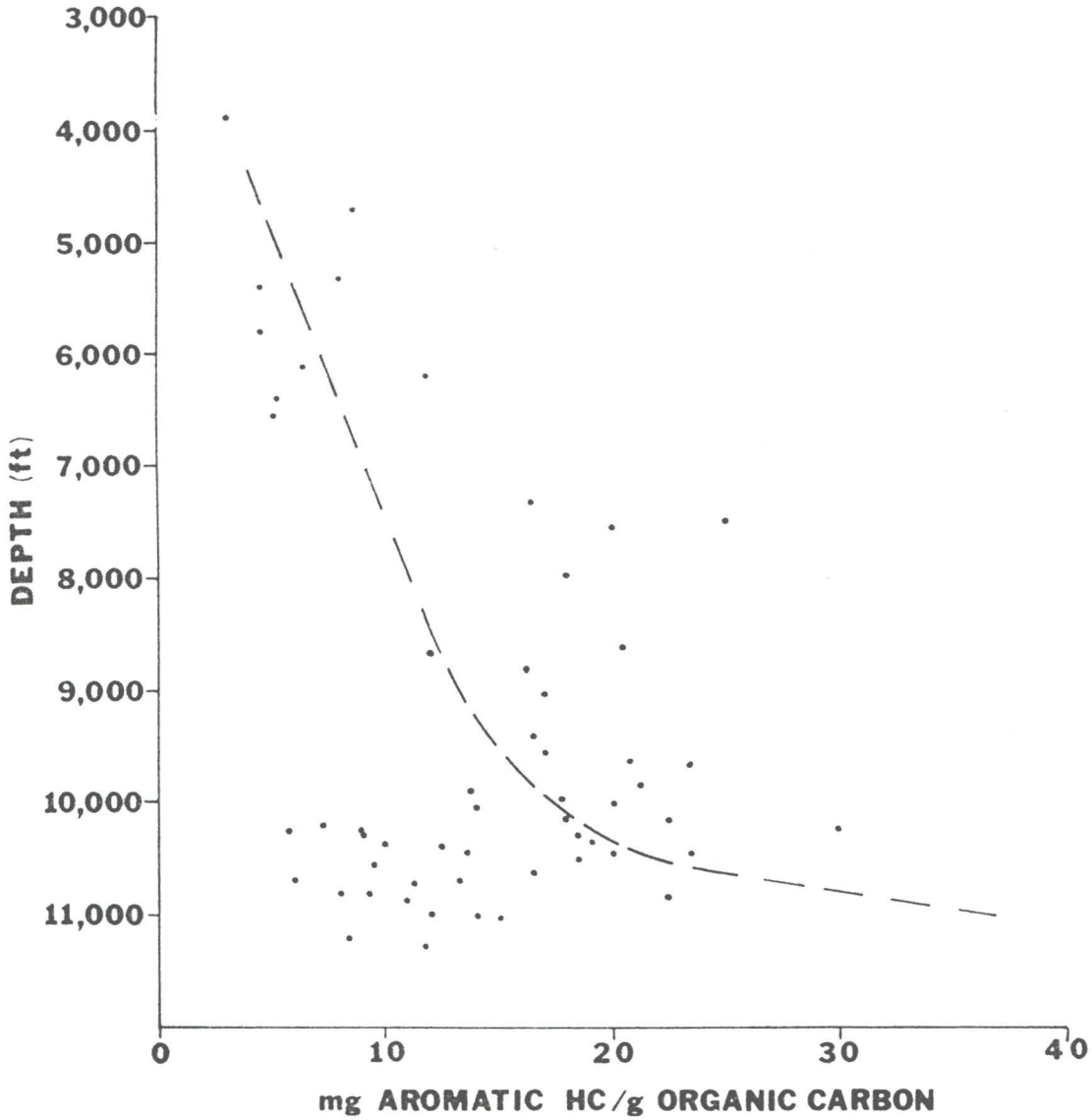


Fig. 31. Ratio of $C_{15}+$ aromatic hydrocarbons to organic carbon (mg/g) versus depth for the Bakken shale.

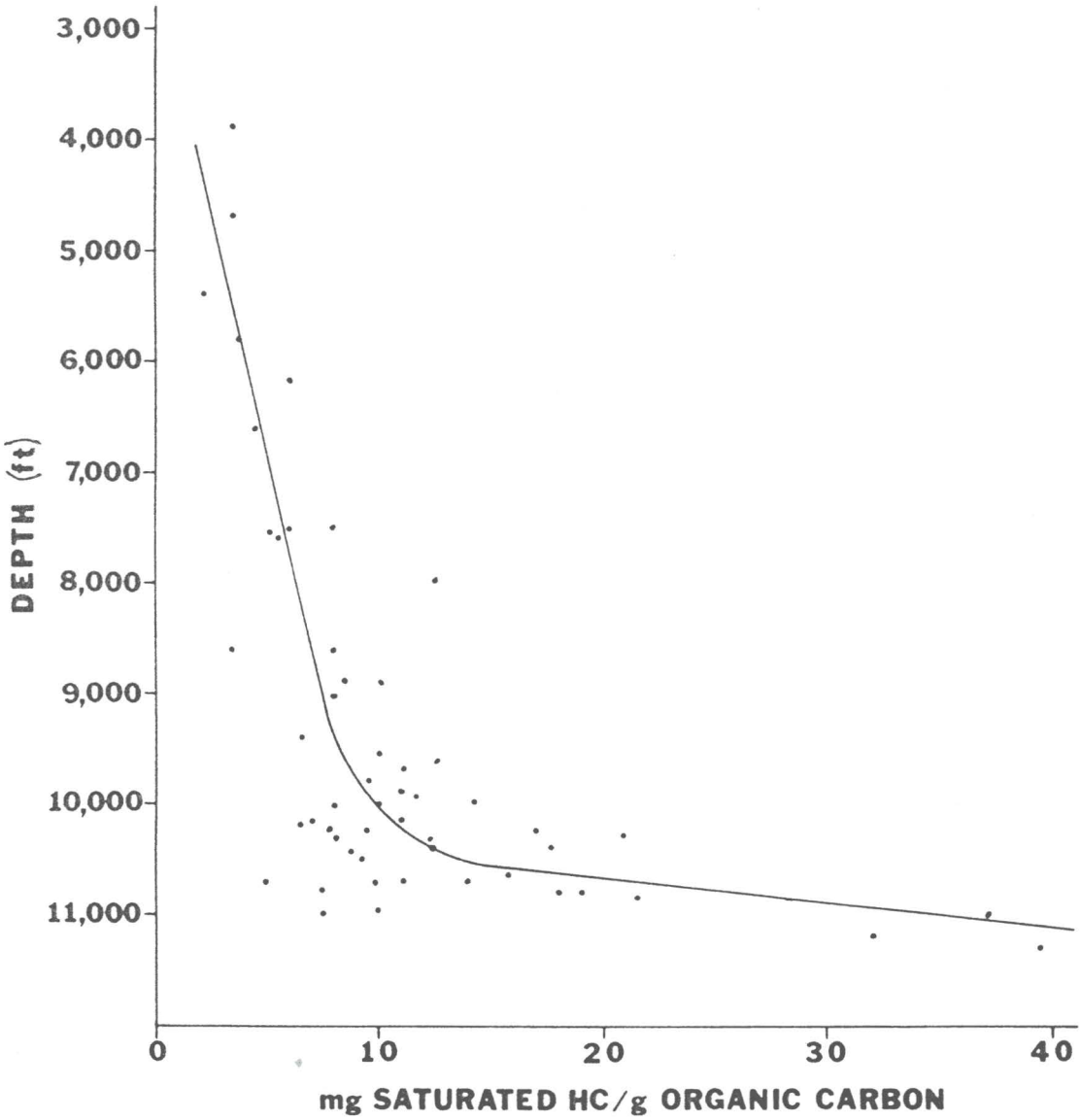


Fig. 32. Ratio of $C_{15}+$ saturated hydrocarbons to organic carbon (mg/g) versus depth for the Bakken shale.

hydrocarbons alone (Harry Dembicki, Jr., personal commun., 1982). This might cause an inaccuracy in the amount of aromatic hydrocarbons measured and thereby introduce scatter in the hydrocarbon data. The scatter observed in the aromatic graph might also be explained by preferential primary migration of the aromatic hydrocarbons. The saturated hydrocarbons alone, when plotted against depth (Fig. 32) show a better defined trend, similar to the HC/nonHC ratio.

The map distribution of the HC/OC ratio (Fig. 33) is rather complex and probably affected by migration or analytical error (amount of aromatic HC present). Distinct areas of low HC/OC values along the south and west sides of the Nesson anticline, along the Billings nose, and in the area of the Antelope Oil Field could be interpreted as areas where migration of hydrocarbons from the Bakken has taken place. Vertical fracturing of the Bakken and adjacent rock units is known, or very possible, in these areas (Murray, 1968; Dow, 1974; Meissner, 1978) and could provide a pathway out for oil generated in the Bakken shales. The possible effects of migration on hydrocarbon data in this study will be discussed further in a later section.

Pyrolysis

Thermal analysis, or pyrolysis, can be used to estimate the relative amount of hydrocarbons generated in a source rock and the hydrocarbon-generating capacity of the kerogen. The parameters used in this study to illustrate these properties are known as the ratio of pyrolyzable bitumen to organic carbon and the production index.

Pyrolyzable bitumen content refers to the amount of hydrocarbons generated from the kerogen of the source rock during pyrolysis; this corresponds to the area of the second pyrolysis peak or S_2. When

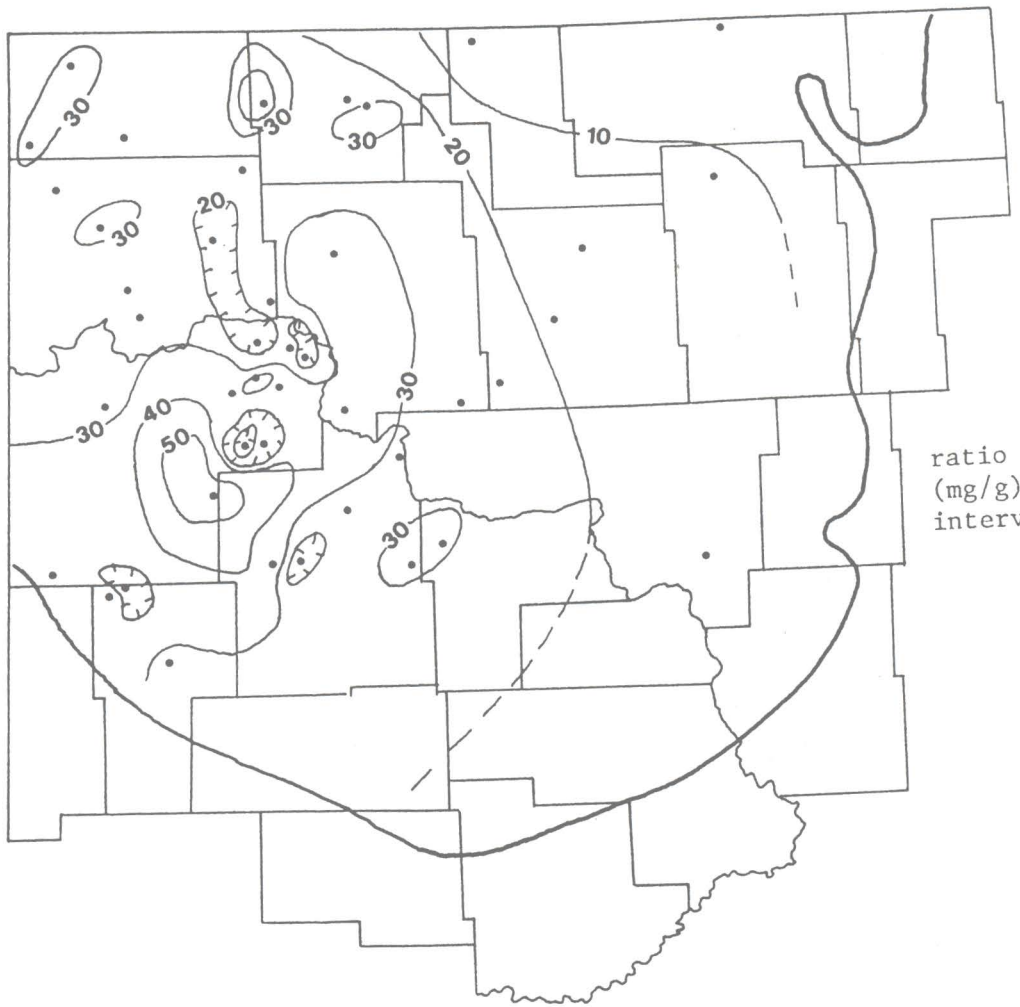


Fig. 33. Contour map of the ratio of C_{15+} hydrocarbons to organic (mg/g) for the Bakken shale. Contour interval is 10 mgHC/gOC.

the S_2 value is normalized to organic carbon and then plotted against depth (Fig. 34) a trend was obtained which represents the progressive breakdown of kerogen with depth. At approximately 9,000 feet the visually fitted curve has a break in slope and the hydrocarbon-generating capacity of the kerogen decreases as oil is generated. From Figure 34, the threshold of oil generation is interpreted to occur at about 9,000 feet of depth. The map distribution of this parameter (Fig. 35) shows a definite decrease to the deeper portions of the basin indicating greater kerogen breakdown (oil generation) in this region.

The production index is a commonly used parameter that is an indication of the extent of the conversion of kerogen to petroleum hydrocarbons (Merewether and Claypool, 1980, p. 493). This parameter is a numerical expression representing the ratio of extractable hydrocarbon to the sum of extractable hydrocarbon plus pyrolyzable hydrocarbon (S_1/S_1+S_2). A plot of this parameter versus depth for the Bakken shales (Fig. 36) displays a well-defined trend with an abrupt increase occurring at about 10,000 feet. The threshold of hydrocarbon generation as seen on this graph could be placed at about 9,000-9,500 feet and intense hydrocarbon generation at approximately 10,000 feet and deeper. The map distribution of this parameter (Fig. 37) shows a clear increase in hydrocarbon generation to the deep part of the basin, as would be expected. The production index does not seem to show much effect that could be attributed to migration. This parameter may be less sensitive to migration effects though, as it takes kerogen breakdown into account.

Vitrinite Reflectance

Vitrinite turned out to be rare in the shales of the Bakken.

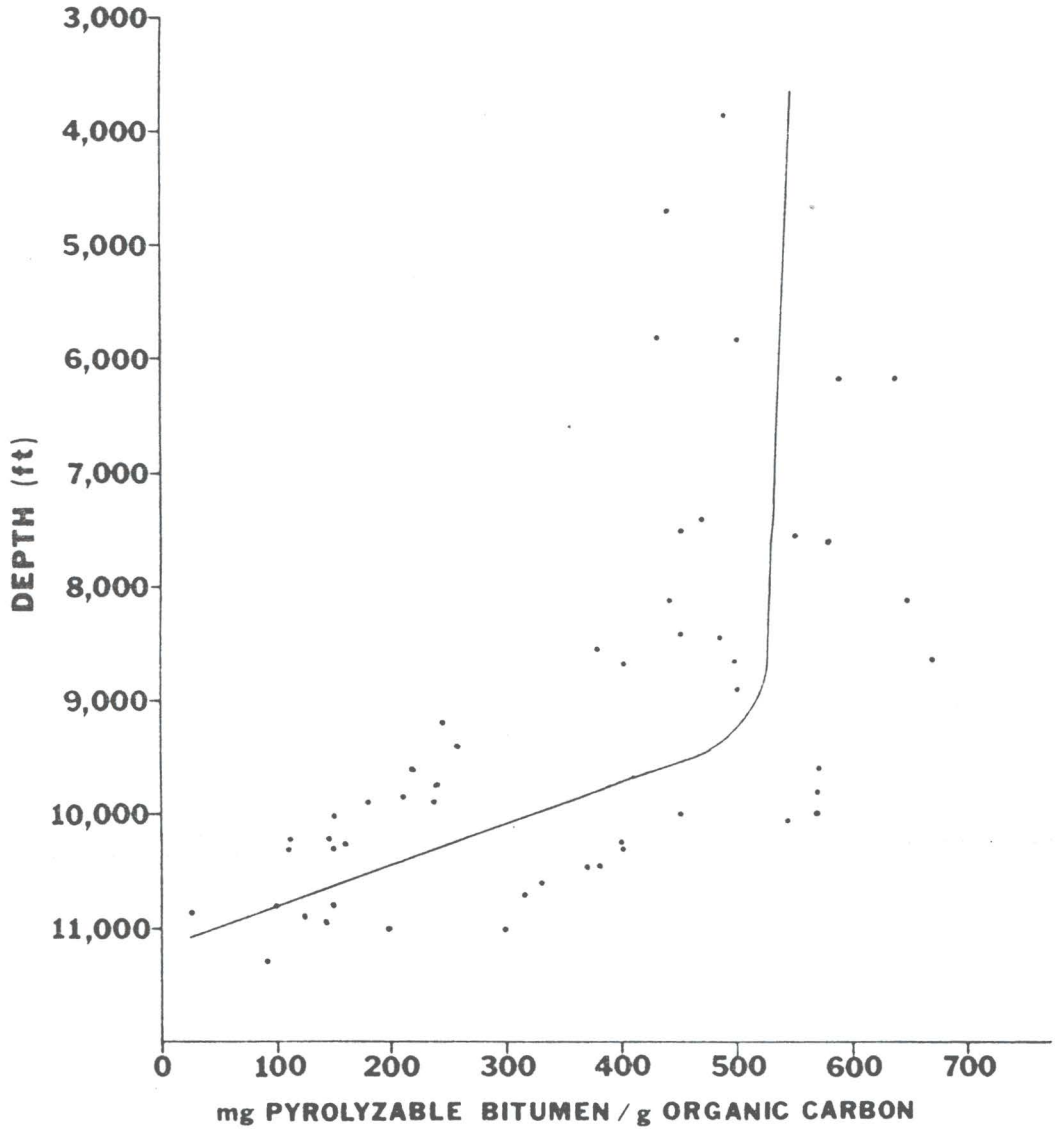


Fig. 34. Ratio of pyrolyzable hydrocarbons to organic carbon (mg/g) versus depth for the Bakken shale.

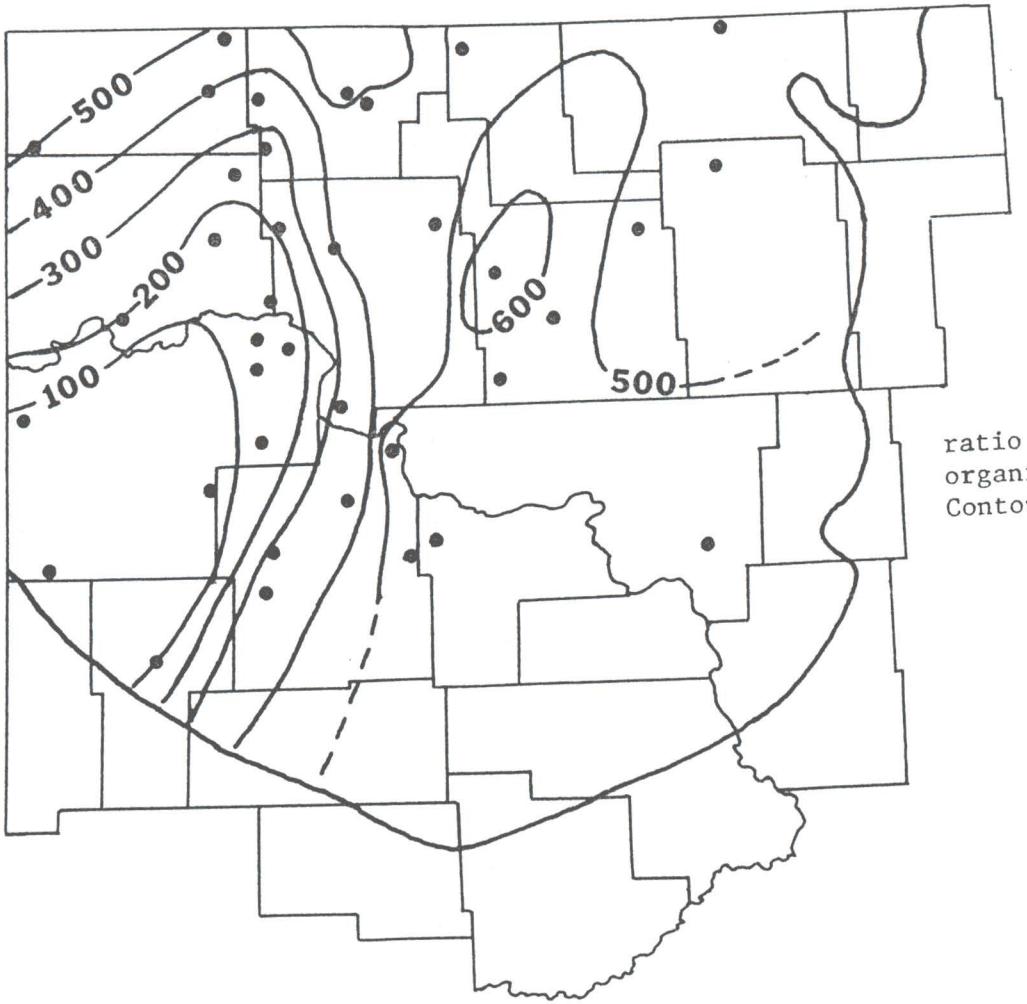


Fig. 35. Contour map of the ratio of pyrolyzable hydrocarbons to organic carbon for the Bakken shale. Contour interval is 100 mgHC/gOC.

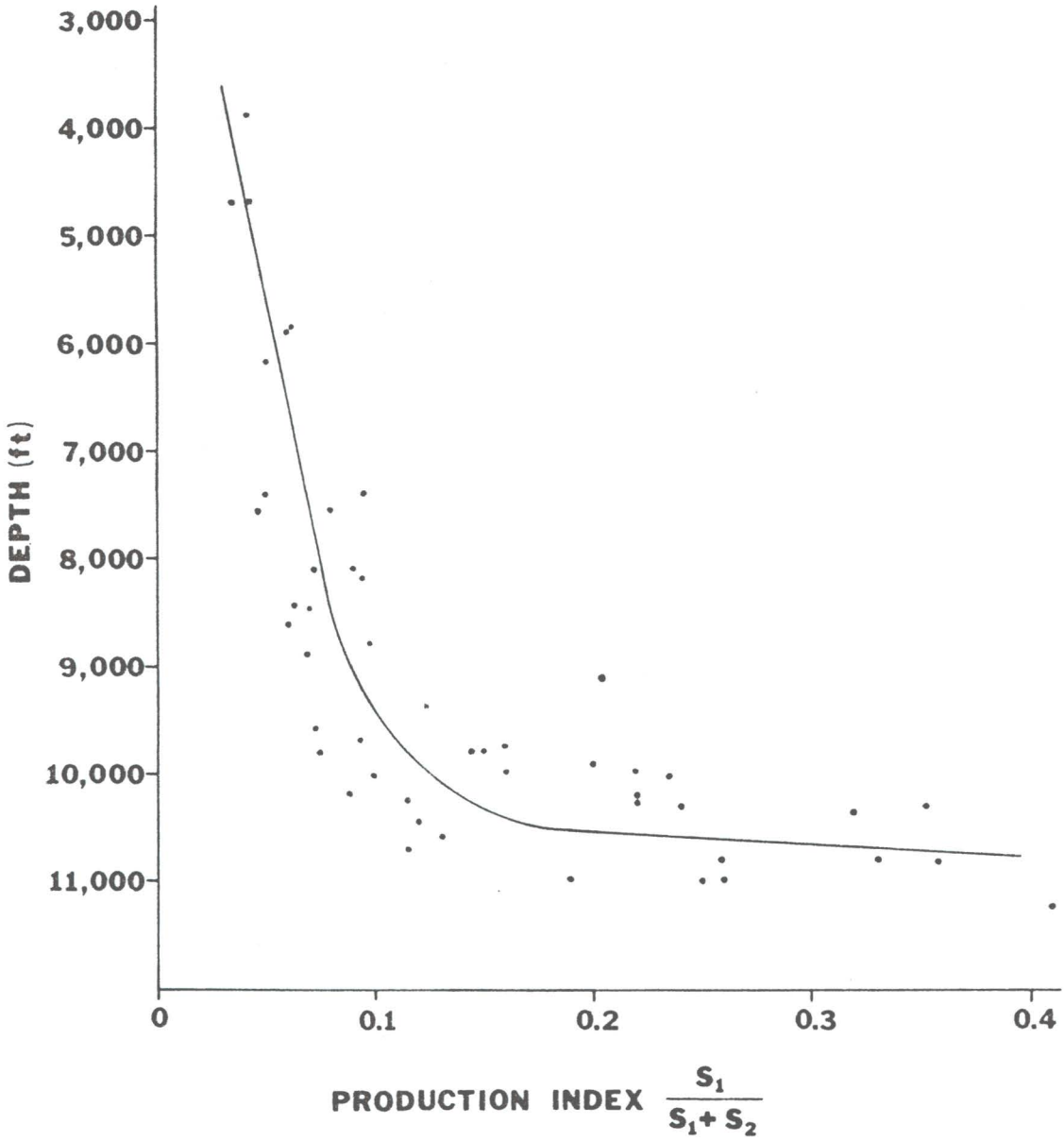


Fig. 36. Ratio of the S_1 pyrolysis peak to the sum of the S_1 and S_2 pyrolysis peaks (production index) versus depth for the Bakken shale.

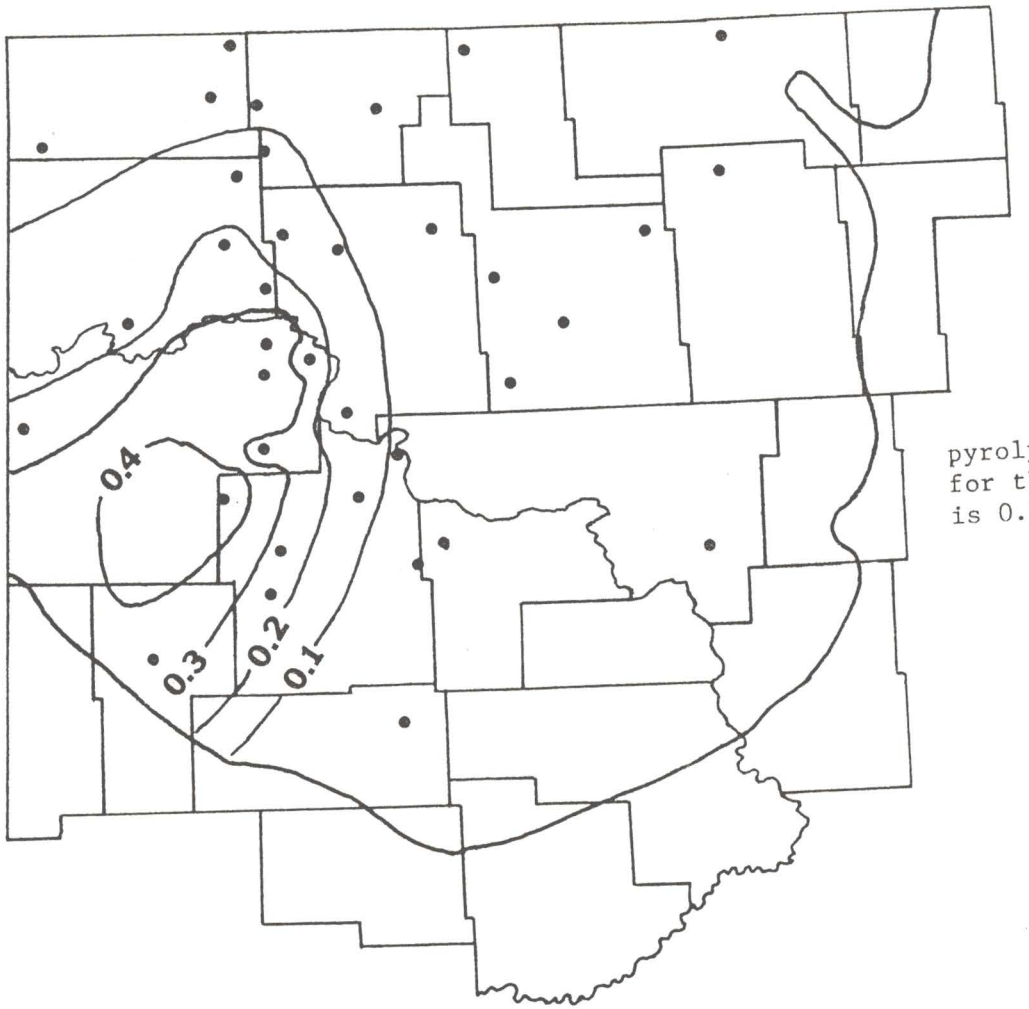


Fig. 37. Contour map of the pyrolysis production index (S_1/S_1+S_2) for the Bakken shale. Contour interval is 0.1.

Only a few samples contained enough vitrinite to obtain a statistically sufficient number of readings. The statistical data for the reflectance values obtained are listed in Appendix H.

The reflectance values that were obtained by the Conoco laboratory are plotted against depth in Figure 38. The dashed line suggests the possible rate of change of vitrinite reflectance with depth. More data are obviously needed to make this relation conclusive; but if this line can be assumed to be approximate, it would support conclusions on the depth at which oil generation began as drawn from pyrolysis and extractable hydrocarbon data. A vitrinite reflectance value of 0.6 is often taken to represent the onset of oil generation (Hunt, 1979, p. 332) and this value occurs at a depth of about 9,200 feet in Figure 38.

A better approach to using vitrinite reflectance to evaluate thermal maturity in the Bakken might be to sample the shales of the Three Forks Formation immediately below the Bakken. Vitrinite should be more abundant in this unit, as vitrinite is derived from terrestrial plant material and the upper Three Forks was probably deposited under terrestrial to marginal marine conditions (McCabe, 1959, p. 43).

Burial and Thermal History

Burial history is an important factor in the timing of maturation of a source rock. For first-order reaction rate oil generation theory, the temperature and length of time at a particular temperature to which a source rock has been subjected are the two most important factors in determining its maturity. The first-order chemical reactions that take place to breakdown kerogen into oil are time- and temperature-dependent. Either a $10^{o}C$ increase in temperature or a doubling of the

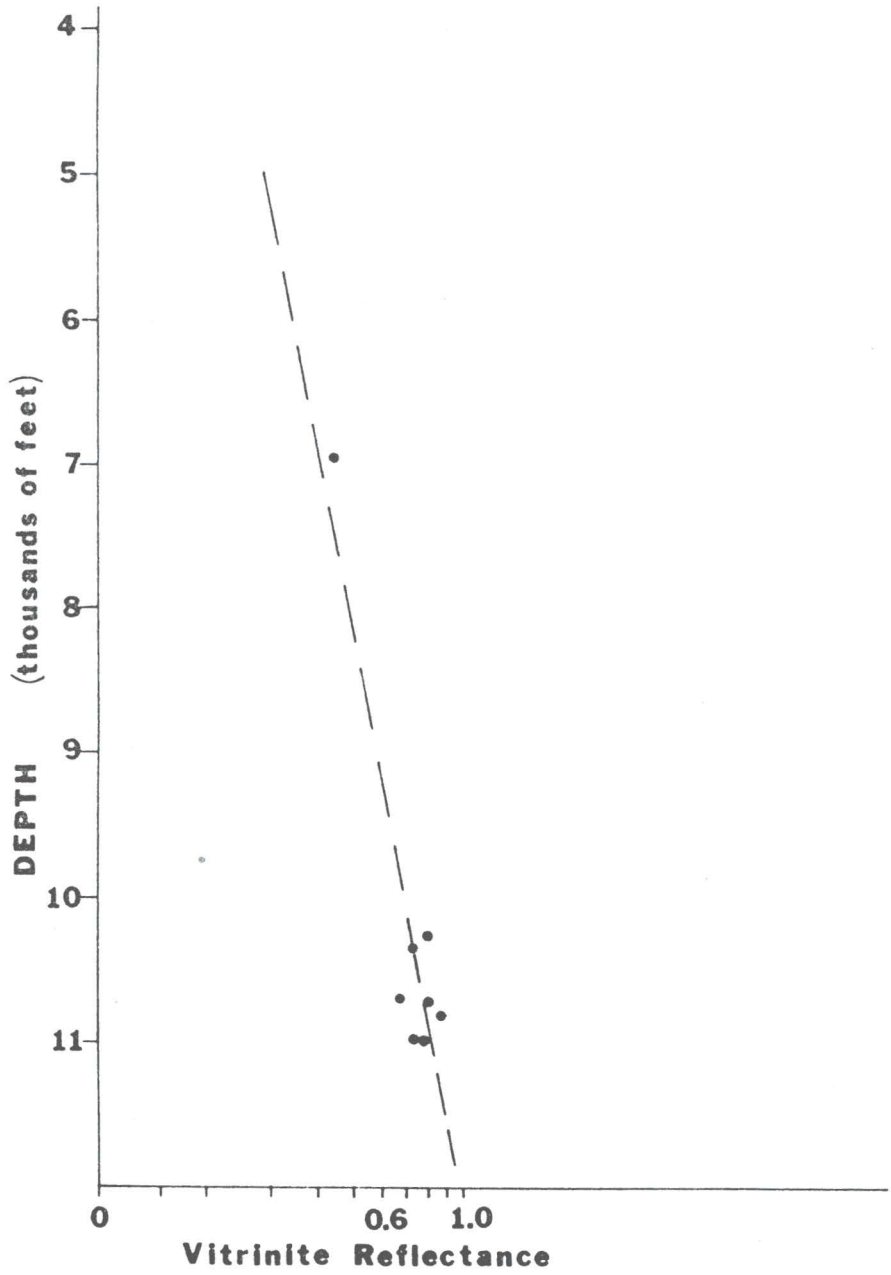


Fig. 38. Vitrinite reflectance versus depth for the Bakken shale.

exposure time of a source rock to a given temperature will double the reaction rate of oil generation (Dow, 1977, p. 88).

The burial history of the Bakken as seen in a simplified regional cross section in North Dakota (Fig. 39) includes four major unconformities located at the base of the Pennsylvanian, at the base of the Spearfish Formation, at the base of the Jurassic, and at the base of the Cretaceous. These unconformities represent pauses in the burial of the Bakken and possible loss of section. Some erosion has undoubtedly taken place from the Tertiary units in western North Dakota, but how much is uncertain.

A useful graphical method for depiciting the burial history of a sedimentary unit was originated by Lopatin (1971) and further refined by Waples (1980). The graphical representation of the Bakken burial history is illustrated in Figure 40. Each line on the graph represents the burial history for a particular area of the basin, and the depth indicates the amount of burial at a particular time. The bottom line (A) represents burial history of the Bakken in the deeper portion of the basin. The three other lines represent the burial history in shallower portions of the basin. The three small upward deflections represent major unconformities. The amount of uplift or sediment loss represented by the magnitude of the upward deflections is qualitative, as little information on the amount of section lost at these unconformities is readily available. The last upward deflection represents possible loss of section since the Paleocene (approximately since the time of deposition of the Sentinel Butte Formation) and, again, is a rough estimate.

Figure 40 can be used to make time-temperature calculations

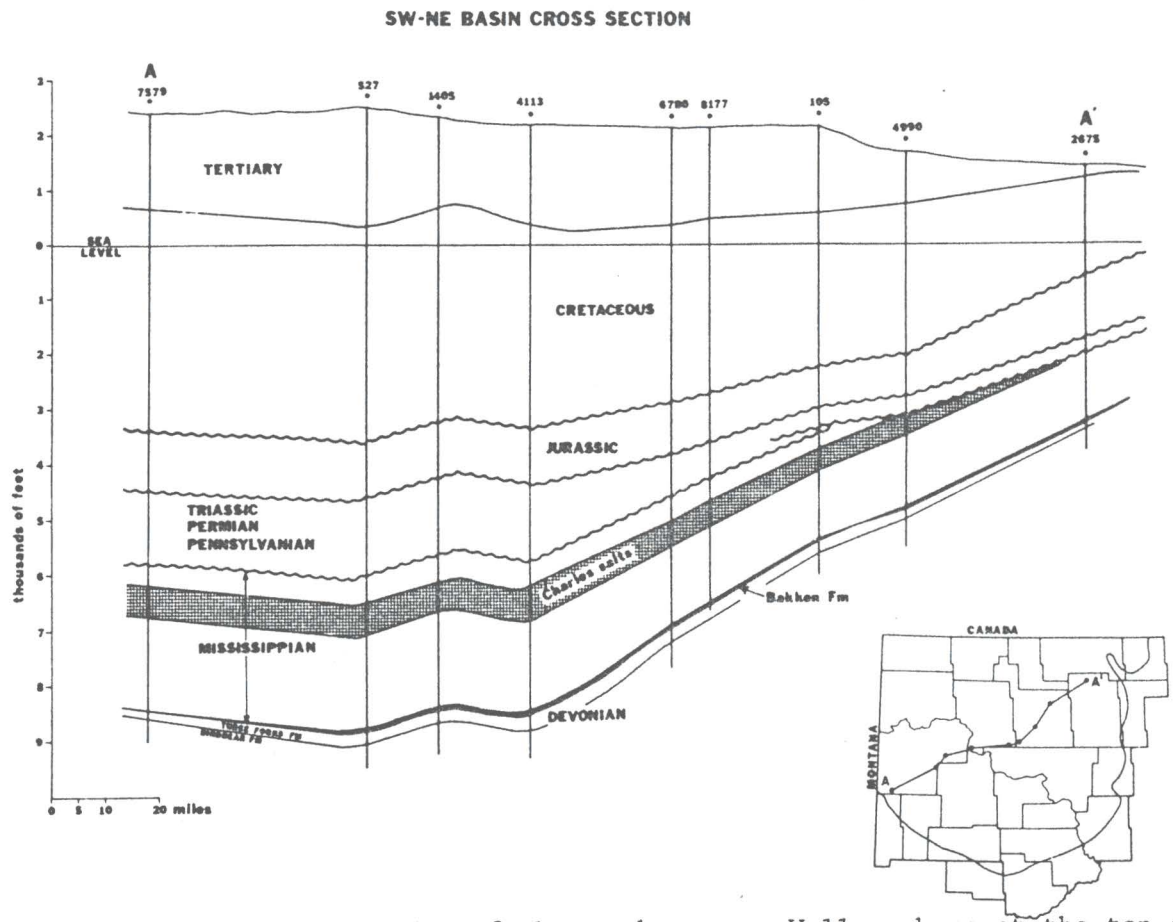


Fig. 39. Regional cross section of the study area. Well numbers at the top of the cross section are those of the North Dakota Geological Survey. Major unconformities are represented by wavy lines.

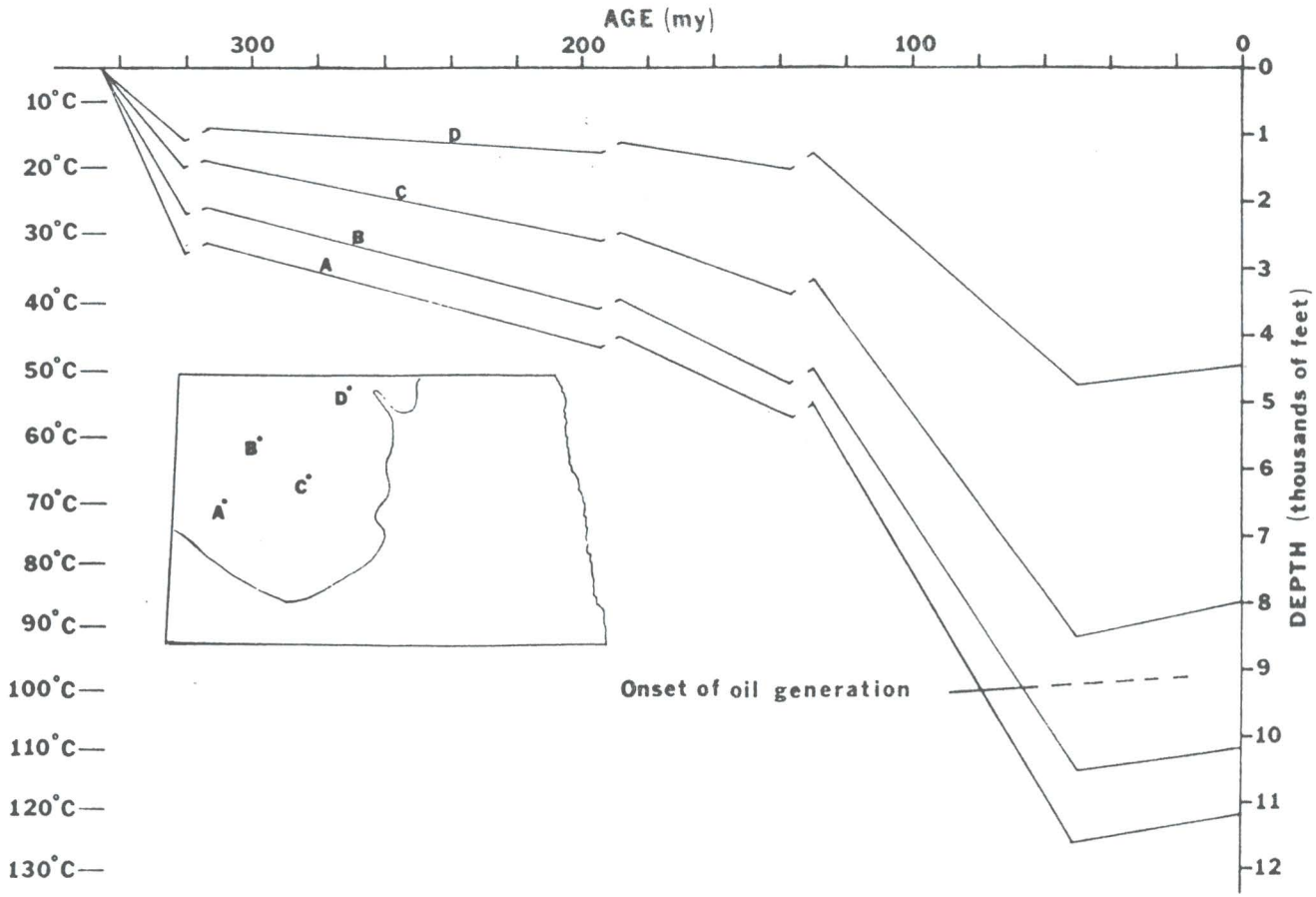


Fig. 40. Graphical illustration of the burial history of the Bakken Formation in four wells (NDGS well nos. A=527, B=3363, C=8177, D=6126). Upward deflections represent possible loss of section from major unconformities. Present day geothermal gradient is plotted on the left hand side of the diagram.

as used by Waples (1980). From these calculations, interpretations can be made pertaining to source rock maturity in the Bakken.

The present day geothermal gradient of the Williston basin (Fig. 40) has been taken from Nixon (1973, p. 151). To make time-temperature calculations from burial history, one starts by estimating, from Figure 40, the amount of time the Bakken has spent in each of the $10^{o}C$ temperature intervals. This amount of time is then multiplied by a temperature factor which increases exponentially for each higher temperature interval (reflecting the exponential dependence of oil generation on temperature). This time-temperature index (TTI) for each interval is then added together to arrive at the total TTI of a given rock unit at a given time. These calculations are summarized in Table 1 for lines A and B in Figure 40.

According to Waples (1980, p. 921) a TTI value of 15 signals the onset of oil generation. For the Bakken this value occurs at about 9,200 feet of burial which is close to the depth estimated from geochemical results. A value of 160 marks the end of oil generation; and for line A, a TTI value of 226 in the temperature interval of $120\text{-}130^{o}C$ (the deepest part of the basin) would indicate that oil generation has been completed in the Bakken in that region. However, this is not substantiated by pyrolysis or extractable hydrocarbon data.

The conclusions or interpretations derived from this method of source-rock analysis should be considered as approximations which carry much less weight than those derived from hard geochemical data. One inherent drawback in the TTI method is that it assumes a constant geothermal gradient during the geologic past. It may be that over the span of 345 million years the gradient has varied considerably, possibly

TABLE 1

CALCULATION OF TTI VALUES FOR BURIAL HISTORY LINES A AND B IN FIGURE 37

Temp. Interval	Temp. Factor	Time(my)	Interval TTI	Total TTI
		LINE A		
10-20 °C	2^{-9}	9	0.018	0.018
20-30	2^{-8}	28	0.112	0.130
30-40	2^{-7}	66	0.516	0.646
40-50	2^{-6}	66	1.031	1.677
50-60	2^{-5}	45	1.406	2.723
60-70	2^{-4}	11	0.688	3.411
70-80	2^{-3}	10	1.250	4.661
80-90	2^{-2}	10	2.500	7.161
90-100	2^{-1}	10	5.000	12.161
100-110	1	10	10.000	22.161
110-120	2	10	20.000	42.161
120-130	4	56	224.000	266.161
		LINE B		
10-20	2^{-9}	12	0.023	0.023
20-30	2^{-8}	56	0.219	0.242
30-40	2^{-7}	68	0.531	0.773
40-50	2^{-6}	60	0.938	1.711
50-60	2^{-5}	28	0.875	2.586
60-70	2^{-4}	12	0.750	3.336
70-80	2^{-3}	12	1.500	4.836
80-90	2^{-2}	12	3.000	7.836
90-100	2^{-1}	12	6.000	13.836
100-110	1	12	12.000	25.836
110-120	2	56	112.000	137.836

being much higher or lower than at present. The only viable means of estimating the thermal history of the Bakken is by vitrinite reflectance values taken from evenly spaced intervals from the entire rock column overlying the Bakken in a single well, and then repeating this procedure for several wells in different portions of the basin.

Two conclusions that can be drawn from Figure 40 are the probable temperature of oil generation and the time of initial oil generation in the Bakken. The temperature at which oil generation was initiated in the Bakken would be approximately 100°C (burial depth of 9,000 feet in Figure 40) assuming that the geothermal gradient has not changed significantly. The time of initial oil generation for the deepest Bakken shale (line A) would be approximately 80 million years ago (late Cretaceous time).

DISCUSSION

Bakken Source Rock Maturity

The maturity of the Bakken shales can be interpreted from graphs and maps made from extractable hydrocarbon and pyrolysis data. The onset of oil generation is picked from plots of the geochemical data with depth at that depth where the visual fits of the data significantly change slope. Intense hydrocarbon generation is taken to begin at that depth where an abrupt change in slope of the line occurs and the line approaches horizontal (Fig. 41). From Figures 28, 32, 34, 36, and 41, the onset of oil generation in the Bakken is interpreted to occur at 9,000 feet and intense oil generation is interpreted to occur at 10,000 feet and deeper.

Figure 42 is a map of the maturity zones in the Bakken and is derived from maps of extractable hydrocarbon and pyrolysis data (Figs. 29, 35, 37). The Bakken shales in the eastern part of the area studied are immature as judged from their low hydrocarbon contents (less than 0.5 HC/nonHC) and high values of pyrolytic hydrocarbons (greater than 500 mgHC/gOC). The second zone depicts the area where the shales are just entering the stage of oil generation. Here the hydrocarbon contents are slightly higher (0.5-1.0 HC/nonHC) and kerogen breakdown is beginning, as seen in lower pyrolytic hydrocarbon values (300-500 mgHC/gOC). The last zone, in the deepest part of the basin, illustrates the area of intense hydrocarbon generation, where hydrocarbon contents are high (greater than 1.0 HC/nonHC) and pyrolytic hydrocarbon values

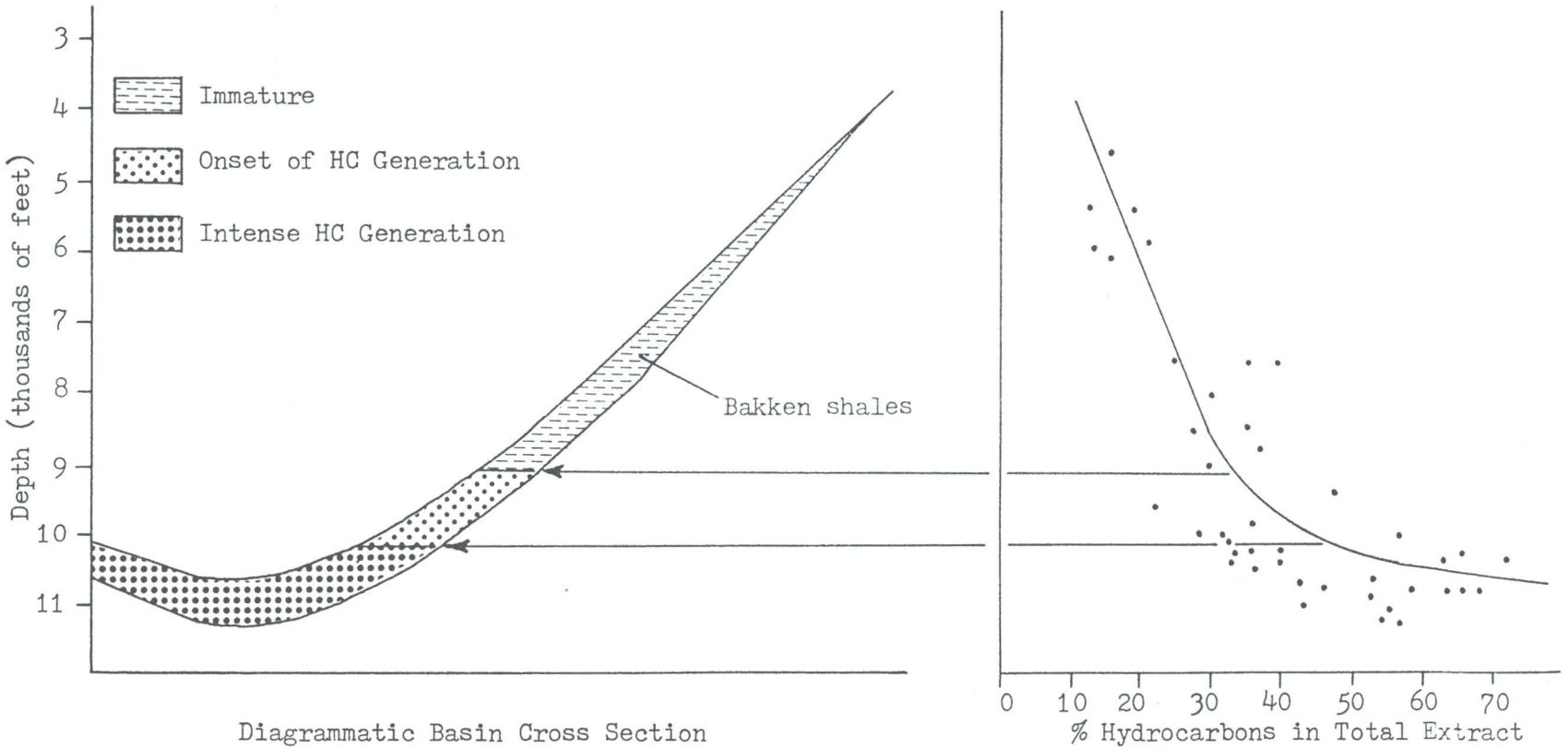


Fig. 41. Interpretations of source rock maturity (A) as made from a graph of solvent-extractable C_{15} + hydrocarbon content (B) of the Bakken shales versus depth. The onset of hydrocarbon generation is taken at that depth where the line in B first significantly changes slope and intense hydrocarbon generation is taken at the depth where an abrupt change in slope of the line occurs and the line approaches horizontal.

Bakken structure contour

Immature - greater than 500 mgHC/gOC S_2; less than 0.5 HC/nonHC; less than 0.1 Production Index

Onset of HC Generation - 300-500 mgHC/gOC S_2; 0.5-1.0 HC/nonHC; 0.1-0.15 Production Index

Intense HC Generation - less than 300 mgHC/gOC S_2; greater than 1.0 HC/nonHC; greater than 0.15 Production Index

Fig. 42. Map of source rock maturity zones in the Bakken shales with superimposed structure contours on top of the Bakken Formation.

are much lower (less than 300 mgHC/gOC). This last zone is here considered the effective source area for the Bakken, where enough hydrocarbons have been generated to charge oil reservoirs in overlying or underlying rock units.

The location of the three maturity zones of the Bakken somewhat follows present-day structure in the basin, but does not seem to be entirely controlled by structure (Fig. 42). The maturity zones deviate from structure mostly to the north and northeast. These differences are probably best explained by different rates of heat flow in some areas of the basin, such as in the area of the Nesson anticline, in the geologic past.

Changes in the fluid content of pore spaces of the Bakken shales, from one maturity zone to the next, are illustrated in Figure 43. At shallow depths (less than 7,000-8,000 feet) where the shales are immature, the pore spaces would contain considerable amounts of water (as seen by low resistivity on well logs) and the bitumen would be composed predominantly of resins and asphaltenes. In the onset of hydrocarbon generation stage, there has probably been a loss of pore water from normal compaction of the shale, and the hydrocarbon content is slightly higher. In the intense generation stage, pore water is very depleted, as evidenced from the lack of water recoveries in drill stem tests of the Bakken in the deep basin, and the bitumen is composed of 40 to 70 percent hydrocarbons.

Expulsion and Migration of Bakken Oil

In a study of oil types and source rocks of the Williston basin, Williams (1974) identified three major oil types and their possible source

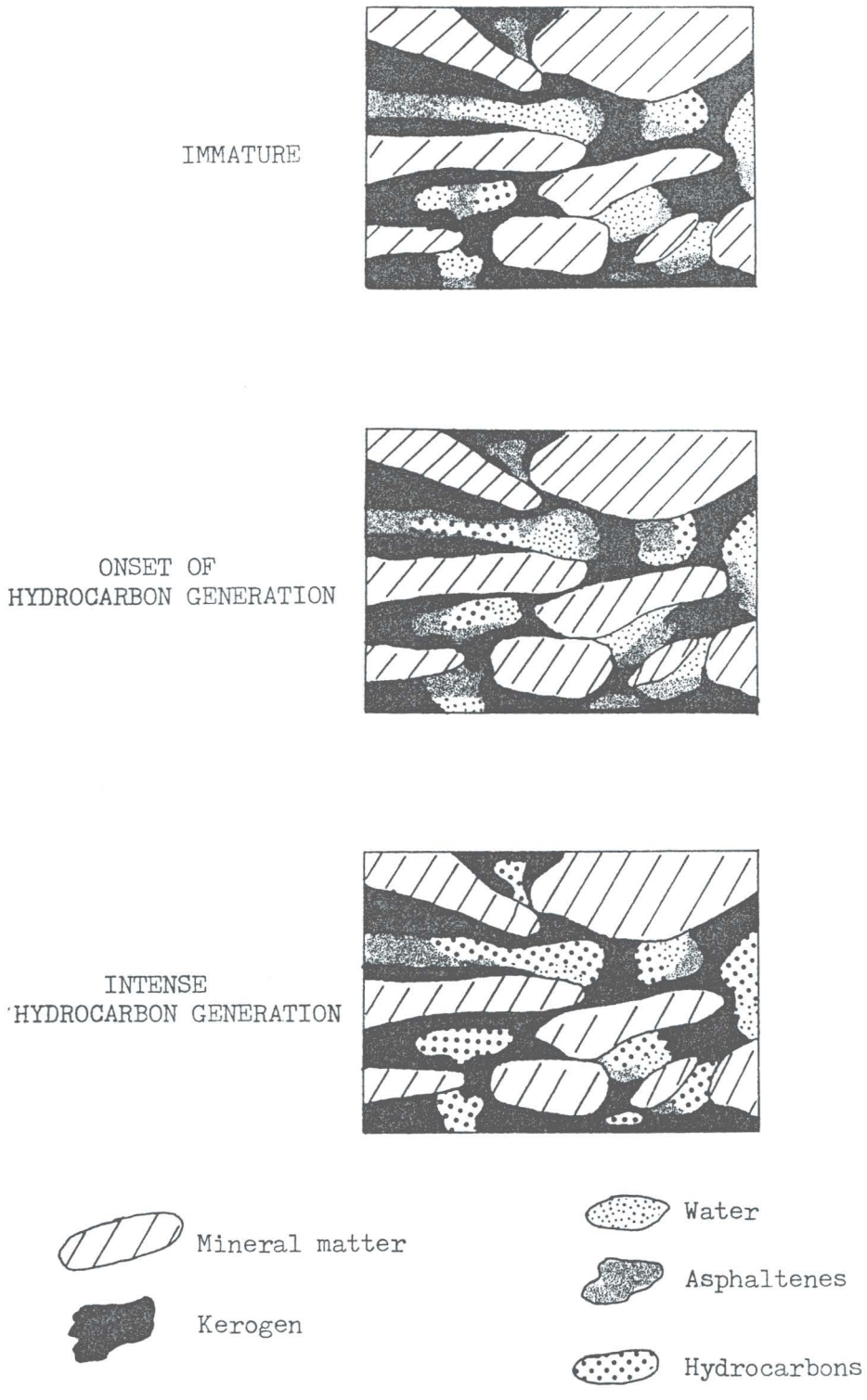


Fig. 43. Diagrammatic representation of the fluid content changes in the Bakken shales with depth (maturity zones).

rock units. The correlation of oil types and respective source rocks was based on similarity in composition (carbon isotope ratios, distribution of C_{15}+ paraffins, C_4-C_7 hydrocarbon type distribution) of oil types and extracts (of soluble organic matter) from selected possible source rock units. Type II oil, as defined by Williams, matched extracts taken from the Bakken shales, and thus the Bakken was considered to be the probable source rock for type II oil in the Williston basin. Type II oil is predominantly found in reservoirs of the Madison Group.

Dow (1974) elaborated on the exploration significance of the oil typing and source rock correlation work done by Williams (1974). The stratigraphic distribution of the oil types defined by Williams and their probable source rocks are illustrated in Figure 44. Type II oil occurs not only in rocks of the overlying Madison group, but also in a few reservoirs of the underlying Birdbear Formation. The amount of type II oil in the Birdbear is very minor and most of the type II oil is found in the Madison Group. Dow's proposed migration scheme for type II oil was based on possible vertical migration of Bakken oil through fractures located primarily on the Nesson anticline. He suggested that this upward vertical migration into the Madison Group was retarded completely upon reaching the salts of the Charles Formation. According to Dow lateral migration of Bakken oil then took place along the base of the Charles salts and through porosity zones in the Mission Canyon Formation (Fig. 45). Bakken oil in post-Madison rocks is present only beyond the depositional edge of the Chalres salts (Dow, 1974, p. 1258). Extensive lateral migration of Bakken oil must have taken place mostly to the north and northeast from the effective source area

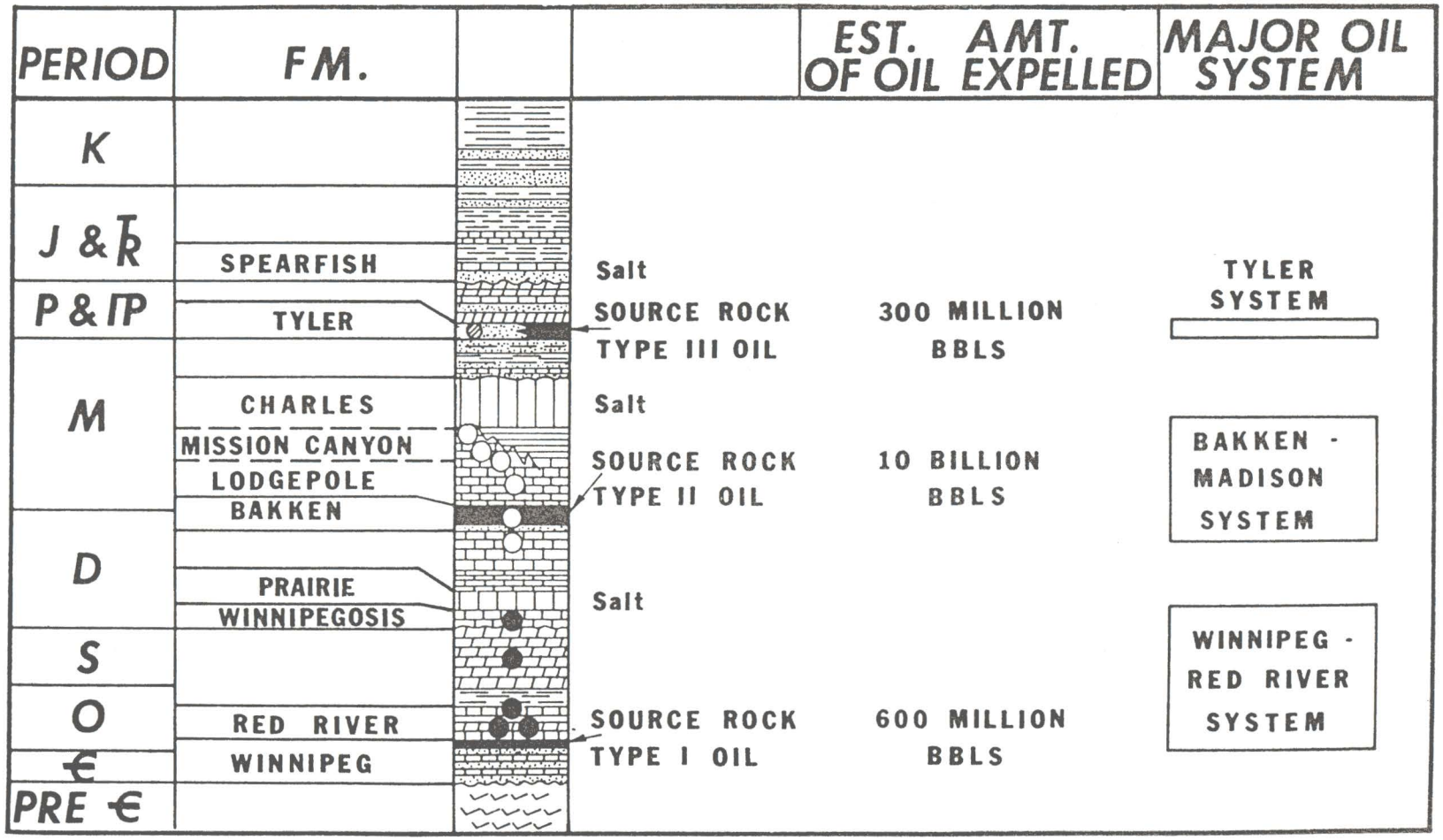


Fig. 44. Schematic columnar section showing terminology, vertical distribution of source rocks, oil types, and estimated amount of oil expelled, as determined by Dow (1974). Reproduced with permission of the author (Dow, 1974, p. 1255).

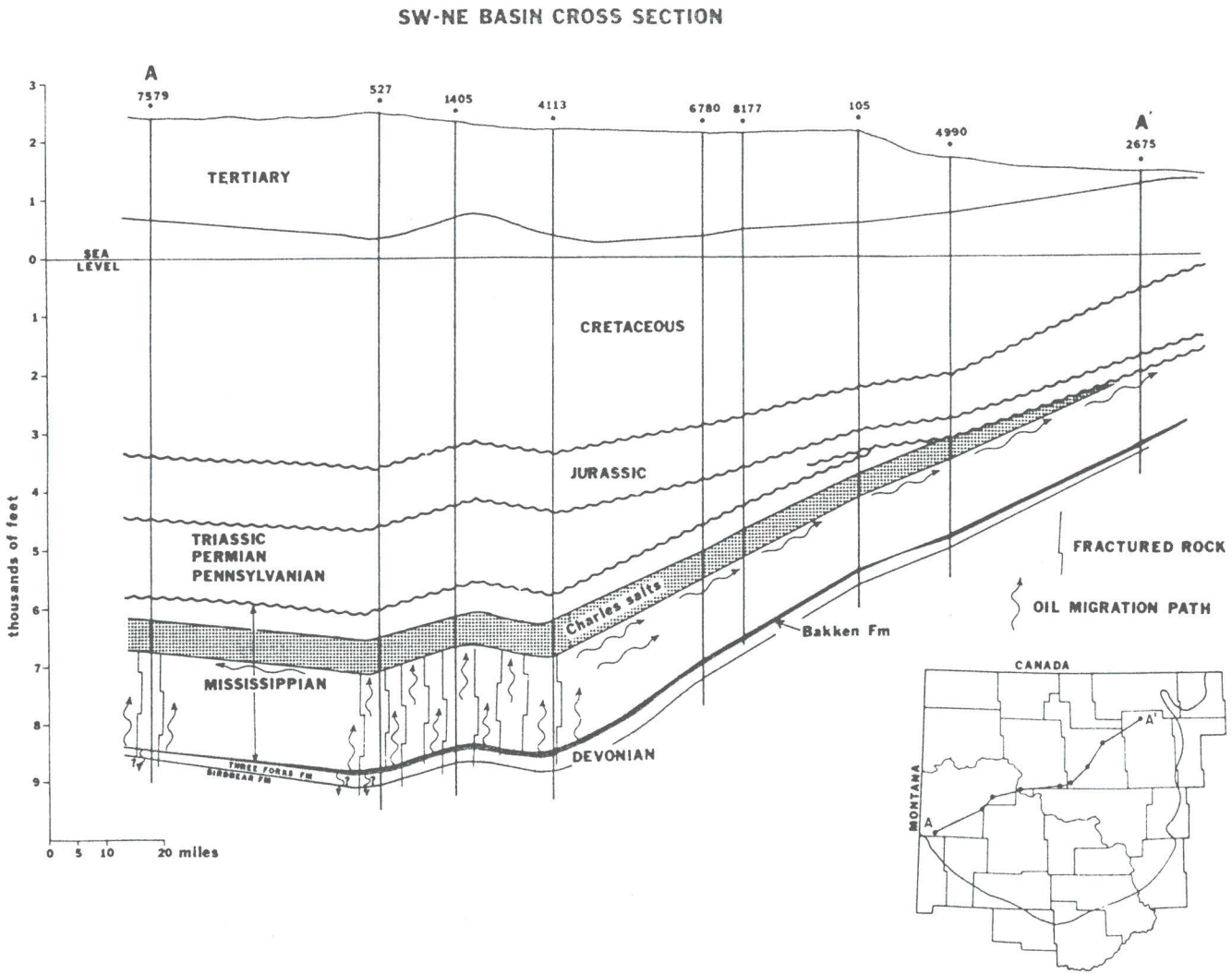


Fig. 45. Regional cross section of the study area showing inferred fracture systems and migration paths of Bakken oil. Well numbers at the top of the section are those of the North Dakota Geological Survey. Major unconformities are represented by wavy lines.

of the Bakken as suggested by the map distribution of type II oil in Madison rocks (Fig. 46). Meissner (1978, p. 225) believed that downward migration of Bakken oil into the Birdbear was controlled by fractures also, and that overpressuring in the Bakken provided a driving force to push oil downward into the more normally pressured Birdbear reservoirs. Meissner also stated that this downward migration through the Three Forks Formation must have been inefficient, compared to upward migration to the Madison Group, and is essentially limited to the western flank of the basin where the Lodgepole Formation becomes siliceous and fracturing occurs preferentially downward through the Three Forks.

Due to the impermeable nature of the overlying Lodgepole and the underlying Three Forks Formation, it would seem that fracture systems are the most reasonable means for oil to migrate from the Bakken and for secondary vertical migration to occur. These fracture systems are known to occur along the Nesson anticline (Dow, 1974), at Antelope Oil Field (Murray, 1968), and are likely to occur in the vicinity of the Billings nose. It may be possible that vertical fracture systems are much more extensive than in these three areas alone; and, as Meissner (1978) stated, the fracturing might occur over most of the area of overpressuring in the Bakken.

A limited amount of lateral oil migration may have occurred in the Bakken middle member where the formation is overpressured. High pressures may have been able to slowly move Bakken oil through even the low permeability (less than 0.1 md) of the middle member. This lateral migration would essentially be confined to the area of overpressured Bakken.

The type of primary migration taking place in the Bakken is not

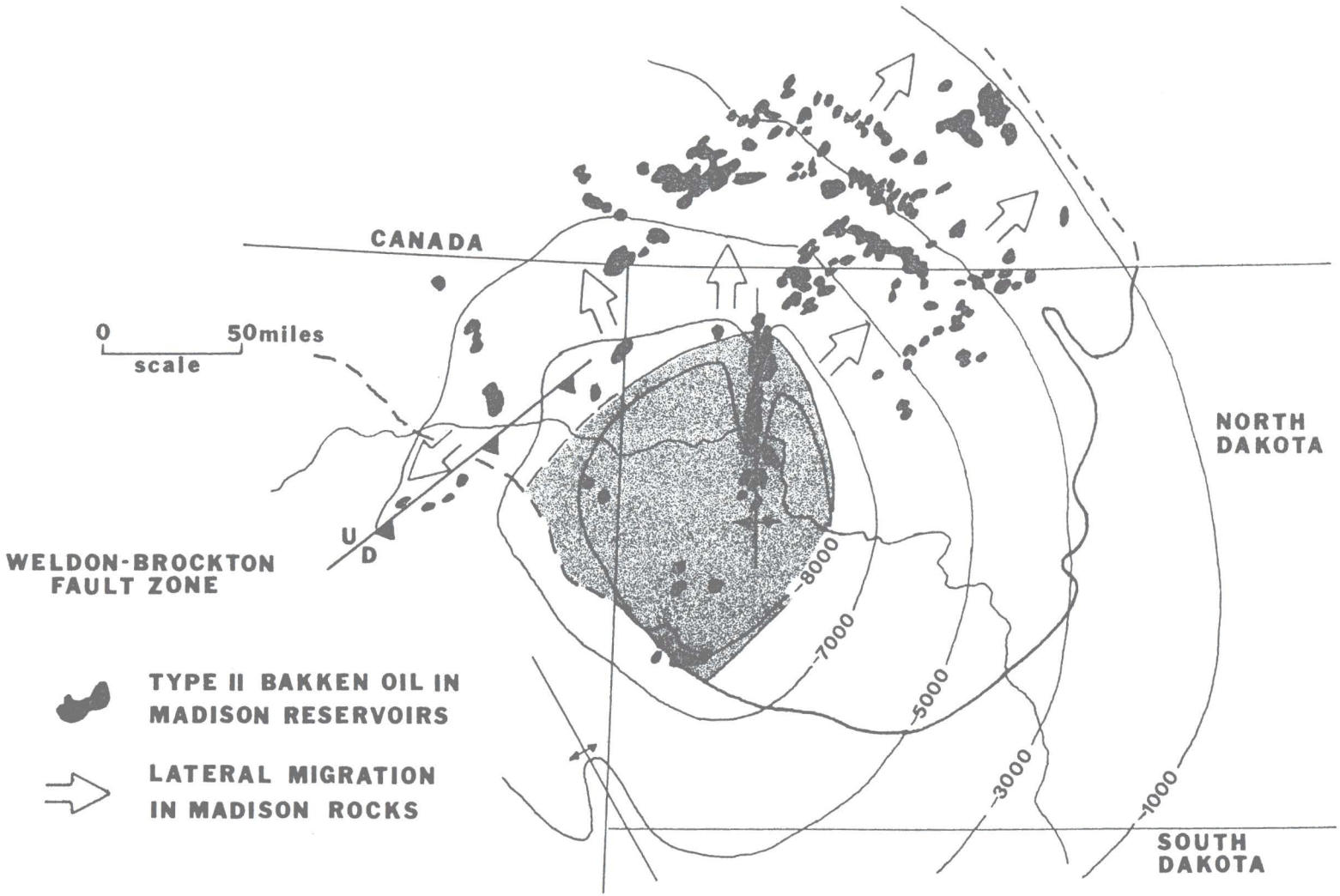


Fig. 46. Bakken structure map showing distribution of type II oil in reservoirs of the Madison Group and lateral migration paths of type II oil from the effective Bakken source area (shaded) (Modified from Dow, 1974, p. 1258).

well known, but continuous-phase oil migration seems likely. Continuous-phase (or bulk) oil migration refers to the movement of oil within and out of a source rock in a single, continuous, oil (liquid) phase. This movement is believed to be caused by high differential pressures within the rock. Jones (1980, p. 49) presented some mass balance calculations to demonstrate that continuous-phase migration was the most likely for the Bakken and that migration by aqueous solution was unlikely.

Possible Effects of Migration on Hydrocarbon Data

Primary migration of hydrocarbons could affect the graphs and maps of hydrocarbon data by causing depletion or enhancement of the indigenous hydrocarbon content of the Bakken shales. Graphs of hydrocarbon data with depth that do not involve a ratio with organic carbon, such as the HC/nonHC graph (Fig. 28) seem to show less pronounced effects that could be attributed to migration than those hydrocarbon parameters that are normalized to organic carbon (Figs. 30, 31, 32). As the total extract usually accounts for less than 10 percent of the total organic carbon in the black shales (Appendix E), organic carbon values reflect mostly kerogen content (solid organic matter) and would thus be a parameter which is not subject to change by migration. This might cause the effects of migration of bitumen to be more noticeable when normalized to organic carbon values. The HC/nonHC ratio shows less pronounced effects of migration, as it is possible that both hydrocarbons and nonhydrocarbons migrated out in somewhat equal proportions (consistent with continuous-phase oil migration). The effects that do show up with this parameter would probably be the result of preferential migration of hydrocarbons over the heavier nonhydrocarbons.

The map distribution of the HC/OC ratio has interesting coincidences between low hydrocarbon content in deep (mature) basin areas and areas where migration of oil out of the Bakken might be expected, as on the flanks of the Nesson anticline, the Antelope structure, and the Billings nose (Fig. 33). Fracturing with some possible associated faulting is known or likely in these areas, especially at Antelope Field (Meissner, 1978, p. 221). Oil generated in the Bakken escaping along these fractures might explain the low hydrocarbon to organic carbon ratios observed in these areas. Higher hydrocarbon to organic carbon ratios than expected, such as those in Divide and Burke Counties, might be explained by northward primary migration of Bakken oil -- the predominant migration direction of type II oil in Madison rocks shown by Dow (1974).

As a great deal of the scatter (and complex map distribution) in the HC/OC ratio is due to variation in the aromatic hydrocarbon content, analytic error in determining the actual amount of aromatic hydrocarbons present is a possible explanation for the erratic distribution of HC/OC values. Preferential migration of the aromatic hydrocarbons is another possibility, but usually the saturated hydrocarbons are the most easily moved and preferential migration of aromatic hydrocarbons would not be expected for continuous-phase (or bulk) oil migration.

There seems to be at least some indication that migration of hydrocarbons from the Bakken has taken place and affected hydrocarbon data in this study, although it is difficult to prove at this time.

Time of Initial Oil Expulsion

The timing of initial oil expulsion from a source rock is dif-

ficult to resolve in source rock studies, and it usually involves a certain amount of guesswork. From the burial history diagram of Figure 40, one can see that initial oil generation is labelled as having begun approximately in late Cretaceous time (80 my ago). For continuous-phase oil migration, the pore spaces of the Bakken shales would have to have been completely saturated with oil before expulsion could begin, and oil generation would have to have been actively occurring to supply new hydrocarbons to the pore spaces to keep them charged and somewhat overpressured. There must have been a certain amount of time lapse between the start of oil generation and oil expulsion in the Bakken. Assuming that expulsion could occur as soon as oil saturation of the pore spaces had occurred, it would seem logical that expulsion occurred when a burial depth of approximately 9,500 to 10,000 feet was attained. At this depth, intense oil generation had been reached and more than enough oil would probably have been generated to saturate the shale pores. As seen on the burial history diagram (Fig. 40), the Bakken reached 9,500 to 10,000 feet of burial in the deep portion of the basin (line A) 70-80 million years ago (late Cretaceous time).

Oil Exploration in the Bakken Formation

A comparison between the areas of Bakken oil and gas production and the areas of source rock maturity of the Bakken shales shows all of the production, within the study area at least, to be within the intense hydrocarbon generation zone (Fig. 47). Some Bakken production has been established in Montana that would lie outside this maturity zone, such as the Salt Creek Field in northwestern Montana (Meissner, 1978, p. 209). The coincidence of the occurrence of most Bakken production

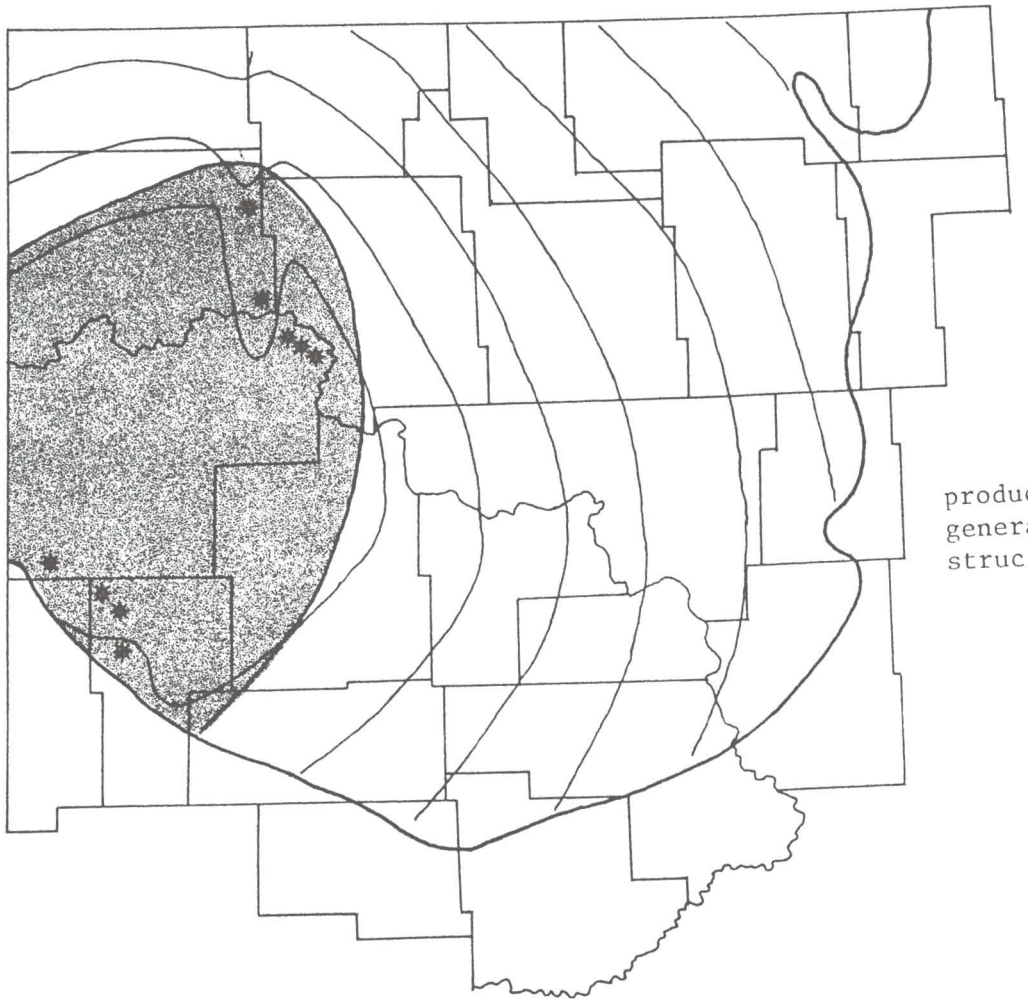


Fig. 47. Map of Bakken oil production and intense hydrocarbon generation zone (shaded), with Bakken structure contours superimposed.

within the intense generation zone may be the result of restricted lateral migration in the Lodgepole-Bakken-Three Forks section so that most of this Bakken oil was generated and accumulated in close proximity. Some lateral migration, however, would be necessary to explain the presence of oil in the Bakken outside the intense generation zone unless this oil was not generated in the Bakken shales.

As fracturing appears to be the factor controlling Bakken production, a logical exploration strategy for Bakken oil accumulations would concentrate on areas within the intense generation zone where fracturing could be expected (sufficient structural curvature). Perforating the shales of the formation along with the middle member is recommended, as a significant portion of Bakken production may arise from fractured shale. Most of the Bakken production in North Dakota is associated with fracturing and only the minor occurrences of Bakken oil in the West Tioga Field and in the East Hofflund Field along the Nesson anticline may not be associated with fracturing.

CONCLUSIONS

The Bakken shales were probably deposited in an offshore, marine, anoxic environment where anoxic conditions were caused by either silling of the basin or the establishment of upwelling currents. The derivation of organic matter from planktonic algae in this depositional environment resulted in very organic-rich (average of 11.33 weight percent organic carbon) black shales. This organic material, as seen in thin section, is distributed rather evenly in the shales and not concentrated in lenses or laminations. The Bakken shales have high organic matter contents throughout their lateral extent, and high amounts of indigenous bitumen (mostly resins and asphaltenes) where they are immature. The amorphous-sapropelic kerogen present in the Bakken shales has a high hydrogen content and makes an excellent petroleum source material.

Hydrocarbon content and thermal kerogen breakdown increase greatly in the Bakken shales where they are buried, on the average, greater than 9,000 feet. The onset of hydrocarbon generation and intense hydrocarbon generation is postulated to occur at depths of 9,000 and 10,000 feet respectively. The map distribution of Bakken maturity zones somewhat follows present-day structure in the basin but deviates from structure to the north and northeast. The area of the Bakken that forms an effective source for oil lies mostly in Williams, McKenzie, Dunn, and Billings Counties. Oil generation was probably initiated in the Bakken about 80 million years ago (late Cretaceous time) at a temperature of 100^{o}C, with initial oil expulsion from the Bakken occurring

70-80 million years ago (late Cretaceous time).

Vertical fracture systems located primarily along the Nesson anticline, Antelope Oil Field, and the Billings nose seem the most reasonable way for oil to migrate from the Bakken into adjacent rock units. Areas of low HC/OC ratio values may delineate areas where migration of hydrocarbons from the Bakken has taken place, such as in the three areas mentioned above. Most of the present Bakken production lies within the area of intense hydrocarbon generation, and sites of fracturing of the Bakken within this area would seem to offer the greatest promise for future Bakken production.

APPENDICES

APPENDIX A

APPENDIX A - Name and Location of Wells Used in This Study

Well numbers in the far left column are those of the North Dakota Geological Survey and are listed in numerical order. Locations are based on the standard Land Office Grid System. Under the location heading, QQ stands for first and second quarter of section; S, T, and R stand for section, township, and range, respectively. All townships in North Dakota are north and all ranges are west of the principal baseline and meridian. County abbreviations used in this appendix are listed below.

Bil - Billings
Bot - Bottineau
Burk - Burke
Burl - Burleigh
Div - Divide
Dunn - Dunn
Gol - Golden Valley
Gra - Grant
Het - Hettinger
McH - McHenry
McK - McKenzie
McL - McLean
Mer - Mercer
Mort - Morton
Moun - Mountrail
Oli - Oliver
Pie - Pierce
Ren - Renville
Rol - Rolette
Sher - Sheridan
Sta - Stark
Ward - Ward
Wil - Williams

TABLE 2

LEGAL DESCRIPTION OF WELLS USED IN THIS STUDY

Well No.	Location QQ	S-T-R	County	Operator	Well Name
15	C SE	18-141-81	Oli	Carter Oil Co.	E. L. Semling #1
21	NWNE	28-142-89	Mer	Kelly-Plymouth	Fritz Leutz #1
32	SWNW	12-157-95	Wil	Amerada Petroleum Corp.	Bakken #1
39	NESW	3-157-78	McH	Hunt Oil Co.	W. B. Shoemaker #1
49	SWSW	28-150-80	McL	Stanolind Oil and Gas Co.	McClean County #1
52	NENE	24-156-85	Ward	Wanette Oil Co.	M. O. Lee et al. #1
61	NWSE	17-153-77	McH	Hunt Oil Co.	Peter Lennertz #1
83	SENW	23-161-73	Rol	Lion Oil Co.	Sebelius #1
105	SWNE	2-153-85	Ward	Stanolind Oil and Gas Co.	Walter & Ingerberg Waswick #1
110	NWNW	23-163-75	Bot	Lion Oil Co.	Huss #1
126	SWSE	33-156-83	Ward	Quintana Petroleum Corp.	C. W. Linnertz #1
133	SWSW	30-139-86	Mort	Deep Rock Oil Co.	H. Johnson "A" #1
170	SESW	2-163-77	Bot	Lion Oil Co.	Magnuson #1
286	SWNE	32-164-78	Bot	Lion Oil Co.	Erickson #1
328	NWNW	28-162-74	Bot	Calvert Drilling Co.	E. Charbonneau #1
348	SWSW	12-161-75	Bot	Cardinal Petroleum Co.	Bennison et al. #1
358	SENE	34-156-76	McH	Calvert Drilling Co.	Albert Payne #1
359	SWSE	36-164-74	Bot	Ward-Williston Drilling Co.	North Dakota State #1
392	SWSW	21-157-85	Ward	Sam G. Harrison	J. H. Anderson et al. #1
413	SESW	5-147-93	Dunn	Carter Oil Co.	Edward Lockwood Jr. #1
432	SWSE	2-146-81	McL	H. Hanson Oil Syndicate	N. E. Hanson #H-1
457	NWSW	32-164-78	Bot	Calvert Drilling Co.	George Anderson #1
527	NWNE	13-148-98	McK	California Oil Co.	Rough Creek Unit #1

Well No.	QQ	S-T-R	County	Operator	Well Name
528	NENW	25-157-89	Moun	William Herbert Hunt	L. C. Anderson #1
568	SESW	11-161-72	Rol	Ward-Williston Drilling Co.	State "B" 1 #1
569	SWNW	31-164-70	Rol	S. D. Johnson	C. M. Bryant Estate #1
579	SWSE	3-163-70	Rol	S. D. Johnson	Melvin Tingelstad #1
588	SWSE	33-152-82	Ward	William Herbert Hunt	F. C. Neumann #1
607	SWNE	24-149-93	Dunn	Socony-Vacuum Oil Co.	Angus Kennedy #F 32-24-D
656	NWNE	13-155-82	Ward	William Herbert Hunt	Guy Almy #1
659	NWSW	5-163-72	Rol	Sun Oil Co.	Arthur Espe #1
665	NENE	15-148-76	Sher	Caroline Hunt Trust Estate	John Waltz Jr. #1
685	SWSW	32-163-73	Rol	British-American Oil Producing Co.	P. Wenstad #1
693	SWSW	19-146-76	Sher	Caroline Hunt Trust Estate	Walter E. Bauer #1
763	SESE	14-144-77	Burl	Caroline Hunt Trust Estate	Anton Novy #1
765	SWSW	31-142-76	Burl	Caroline Hunt Trust Estate	Soder Investment Co. #1
769	NWNW	14-154-78	McH	Calvert Drilling Co.	Fred & Signa Wright #1
772	NWNW	23-140-79	Burl	Caroline Hunt Trust Estate	Paul Ryberg #1
780	NWSW	3-157-73	Pie	E. F. Wakefield	Christenson #1
793	SENW	22-149-91	Dunn	Mobil Prod. Co.	Pegasus Div. Solomon Bird Bear #1
806	NESE	14-163-73	Rol	British-American Oil Producing Co.	Henry Dietrich #1
895	NWNW	14-162-76	Bot	Lion Oil Co.	Wallace Hall #1
917	NESE	22-160-72	Rol	Lion Oil Co.	Peter P. Nelson #1
955	SWNW	7-163-74	Bot	Lion Oil Co.	Roy Larson #1
981	SENE	26-163-72	Rol	Lion Oil Co.	Peter Danielson #1
999	SWNE	23-154-100	Wil	Texaco Inc.	J. M. Donahue #1
1069	NWNW	1-159-82	Bot	Cardinal, Kaufman, Great Plains Et Al.	Beatrice M. Keeler #1
1102	SWNE	2-161-74	Bot	Cardinal Petroleum Co.	J. Andrieux #1
1202	SWNW	6-152-94	McK	Amerada Petroleum Corp.	Jens Strand #1
1354	NWNW	26-156-77	McH	Monsanto Chemical Co.	Ed #1
1385	SESW	16-156-95	Wil	Amerada Petroleum Corp.	North Dakota "A" Unit #9
1405	NWNE	27-150-96	McK	Gofor Oil Inc.	Catherine E. Peck #2
1620	NESW	27-139-90	Mor	Pan American Petroleum Corp.	Raymond Yetter #1
1636	C SW	17-156-95	Wil	Amerada Petroleum Corp.	Peterson Davidson Unit #1
1666	SWNE	2-161-73	Rol	General Crude Oil Co.	Kenneth Tooke #1
1673	NESW	23-163-74	Bot	General Crude Oil Co.	Martin Rude #1
1748	NWNE	6-152-94	McK	Amerada Petroleum Corp.	Reed-Norby Unit #1

Well No.	QQ	S-T-R	County	Operator	Well Name
1858	NWNE	25-150-96	McK	Amerada Petroleum Corp.	Minnie Kummer Tract 1 #1
1968	SWNW	30-163-78	Bot	Calvert Drilling Co.	L. T. Hanson #1
2010	NWNE	7-163-102	Div	Carter Oil Co.	Dallas D. Moore #1
2033	SWSW	30-160-94	Burk	Hunt Oil Co.	Carl Overlee #3
2584	SWNE	16-145-101	McK	Shell Oil Co. - Northern Pacific Rail R.	State of North Dakota #32-16-1
2615	NENE	20-146-96	Dunn	Stewart Petroleum Corp.	Jack Dvirnak #1
2618	SWSE	15-145-91	Dunn	Pan American Petroleum Corp.	Jacob Huber #1
2675	NWNW	34-159-79	McH	Amerada Petroleum Corp.	Ted Pfau #1
2746	NESE	8-153-97	McK	William Herbert Hunt	Anna M. Holt #1
2800	SWNW	13-163-89	Burk	Amerada Petroleum Corp.	Gagnum #1
2820	NWSW	5-151-95	McK	Texaco Inc.	F. D. Keogh #1
2828	NWNW	15-154-98	Wil	Texaco Inc.	L. J. Hovde #1
2887	SWSE	20-159-103	Wil	Hunt Oil Co.	Isabele Legge #1
2967	NWSE	3-152-96	McK	Texaco Inc.	A. S. Wisness #2
3007	C NE	30-159-95	Wil	Dallea Petroleum Corp.	Hamlet Unit #2
3044	NENE	27-143-92	Dunn	Amerada Petroleum Corp.	Marie Stelle T-1 #1
3154	NENE	12-163-92	Burk	Mar-Win Development Co.	R. M. Hanson #3-D
3167	SESW	31-153-95	McK	Texaco Inc.	W. Quale #1
3268	NESW	10-139-101	Bil	Amerada Petroleum Corp.	Scoria Unit #8
3363	NWSE	19-157-96	Wil	Texaco Inc.	Clarence Pederson (NCT-1) #1
3392	SESE	12-159-96	Wil	Co-Op Refinery Assoc. Inc.	E. Goetz #1-A
3492	SWSE	25-146-90	Mer	Continental Oil Co.	Gust Schuh #1
3515	NWNW	9-140-93	Sta	Continental Oil Co.	Christ Stoxen #1
3686	NENE	10-151-93	Moun	Occidental Petroleum Corp.	Johnson #1
3827	SESE	20-162-78	Bot	Amerada Petroleum Corp.	Lila Stark #1
3899	NWNW	28-158-95	Wil	Calvert Drilling - Ashland Oil	Carter #1
3920	SESE	23-152-74	Pie	A. J. Hodges Ind. Inc.	Alex Martin #1
3978	SENW	34-137-83	Mor	Austrial Oil Co., Inc.	John J. Leingang #1
4061	NWNW	16-152-93	McK	Mobile Oil Corp.	Grady Heirs #F 11-161
4074	NENE	20-162-95	Div	Calvert-Kelsch & Donlin	A. Legein #1
4113	SENW	4-150-93	Mou	Texaco Inc.	Fort Berthold Allottee 437 #A1
4323	NESW	26-158-95	Wil	Amerada Petroleum Corp.	Hjalmer Ives #B-1
4340	SWSW	2-154-95	Wil	Pan American Petroleum Corp.	Clifford Marmon #1

Well No.	Location QQ	S-T-R	County	Operator	Well Name
4347	NESW	9-163-78	Bot	Cardinal Petroleum Co.	Ekrehagen Estate #1-A
4362	SENW	11-160-81	Bot	Chevron Oil Co.	Jack R. Rogers #1
4389	SWNE	33-141-80	Bur	Tom Vessels	Helen Bourgois #1
4394	SWSW	20-161-97	Div	Texaco Inc.	R. W. Redlin (Nct-1) #1
4423	NWSW	26-162-101	Div	Pan American Petroleum Corp.	Orville C. Raaum #1
4439	NESE	18-151-103	McK	J. H. Moore & R. E. Massengill	Milton W. Olson #1
4507	NENE	21-163-101	Div	Petroleum, Inc.	Ole Hellen #1
4508	NENE	7-161-90	Burk	Northern Pump Co.	Louis Peterson #1
4599	SWSE	25-162-90	Burk	Anschutz Corp.	Ormiston #1
4611	SWSW	36-146-96	Dunn	Helmerich & Payne Inc.	State of North Dakota #1
4618	NENW	17-156-103	Wil	Amerada Petroleum Corp.	Nils Trogstad #1
4655	SESW	31-162-78	Bot	Amerada Petroleum Corp.	H. D. Lillestrand #1
4685	SWSW	19-140-80	Bur	E. C. Johnston Inc.	L. Edwards #1
4723	SENE	23-151-101	McK	Consolidated Oil Gas Co. Inc.	Federal Land Bank et al.
4725	SWSE	24-148-97	Dunn	Kathol Petr. Inc. - Tiddens Petr. Co.	Little Missouri
4754	NESE	21-154-103	Wil	Sam Boren	Rooke #1
4790	SESE	20-159-81	Bot	Union Oil Co. of California	Abra Steen #1
4837	SWNE	12-160-100	Div	Miami Oil Prod. Inc.	Roy Hagen #1
4844	NESW	15-161-81	Bot	General American Oil Co. of Texas	Walter R. Sausker #1-15
4846	NENW	8-163-81	Bot	Lamar Hunt	W. Cranston #1
4923	NWNE	5-156-81	Ward	Union Oil Co. of California	Vernon Olson #1-B-5
4924	NENE	2-161-81	Bot	Union Oil Co. of California	C. M. Huber #1-A-2
4940	SESW	24-142-85	Oli	General American Oil Co. of Texas	Raymond Henke #1-24
4957	NWNW	8-147-93	Dunn	Miami Oil Prod. Inc.	Estate of Hairy Robe #1
4958	SWNE	2-161-91	Durk	John B. Hawley Jr. Trust #1	Florence M. Ingerson #2
4984	NWNE	12-135-92	Het	Pubco Petroleum Corp.	J. Haberstroh #12-2
4990	NWSW	22-156-84	Ward	Anschutz Corp.	Richard Musch #1
4992	NESE	2-156-82	Ward	Union Oil Co. of California	Harold Anderson #1-I-2
5071	NWSW	34-160-81	Bot	Estate of William G. Hetis	E. Van Horn et al. #1
5072	NENE	22-158-94	Moun	Amerada Petroleum Corp.	Albert Erickson #1X
5088	NENW	35-156-93	Moun	Shell Oil Co.	Shell-Texel #21-35
5105	NWNW	28-152-86	Ward	General Crude Oil Co.	Jerome Jensen #1
5114	SENW	21-158-103	Wil	Universal Resources	Agnes Burns #1
5135	C NW	29-161-95	Div	Ashland Oil Inc.	F. Fenster #1-29
5141	SWNE	33-164-77	Bot	Gemini Corp. et al.	Carl #1-X

Well No.	QQ	S-T-R	County	Operator	Well Name
5143	NENW	9-137-97	Sta	Lone Star Producing Co.	Warner #1
5147	SESW	2-160-82	Bot	Hicherson Oil Co.	Streich #1
5158	NENW	13-153-85	Ward	Union Oil Co. of California	Myrtle Hanson #1-C-13
5182	SENW	27-148-101	McK	True Oil Co.	Burlington Northern #22-27
5184	SENE	14-162-77	Bot	Champlin Petroleum Co.	DunBar #1 42-14
5197	NENW	9-157-95	Wil	Amerada Petroleum Corp.	Hemsing #1-9
5248	NENE	10-160-98	Div	Oil Development Co. of Texas	Rogers #1
5255	NESW	22-137-95	Sta	Continental Oil Co.	Feimer - Anger #1
5277	SWSW	11-162-77	Bot	McMoran Exploration Co.	Tonneson #1
5279	NESW	34-157-76	McH	McMoran Exploration Co.	State #1
5280	SWSW	24-161-76	Bot	McMoran Exploration Co.	Deraas #1
5281	SWSW	16-158-75	McH	McMoran Exploration Co.	State #2
5823	NENE	14-158-77	McH	McMoran Exploration Co.	Fairbrother #1
5315	C SE	26-156-86	Wil	Amerada Petroleum Corp.	Beaver Lodge Devonian Unit D-11
5333	SESE	26-156-93	Moun	Shell Oil Co.	Morrow #44X-26
5379	NWNE	5-138-83	Mor	Campbell Partners LTD.	Picha #1
5404	NWSE	23-163-99	Div	Tiger Oil Co.	Mathews #1-23
5410	S2SW	34-154-95	McK	Texaco Inc.	Devonian Unit #7-1
5496	SWNW	5-134-90	Gra	Wainoco Inc.	Krause #22-5
5528	SWNE	29-157-95	Wil	Tiger Oil Co.	Olson #1-29
5535	NWSW	24-160-96	Div	Trend Exploration Co.	Vatne et al. #1
5621	NENW	23-142-97	Dun	Mesa Petroleum Co.	Roshau #1
5692	NENW	32-159-82	Bot	Kirby Exploration Co.	Brooks #1
5762	SENW	32-156-103	Wil	True Oil Co.	Aafedt #22-32
5783	NWNE	35-136-93	Het	Farmers Union Central Exchange	Grosz #2-35
5831	SWSW	23-157-94	Moun	Smokey Oil Co., Inc.	Will #14-23
5908	NWNE	33-164-90	Burk	Chandler & Assoc., Inc.	Wilson #2-23
5919	SESW	30-161-94	Burk	Home Petroleum Corp.	Sonflot Heirs Unit #1
5989	NESE	31-164-95	Div	W. A. Moncrief & Westhoma	Keba Oil & Gas #31-1
6021	SWNW	27-161-82	Bot	Cities Service Oil Co.	Rice A #1
6065	C SE	20-155-96	Wil	Tiger Oil Co.	Mattson #1-20
6087	SWSE	9-157-94	Moun	Tom Brown Inc.	Jorstad #9-34
6114	NENW	6-156-97	Wil	Smokey Oil Co. Inc.	Wheeler #21-6
6126	SWNW	36-163-80	Bot	Placid Oil Co.	Rosendahl #36-5

Well No.	QQ	S-T-R	County	Operator	Well Name
6182	NENW	21-146-94	Dunn	True Oil Co.	Benz #21-21
6186	SENE	29-148-97	Dunn	Supron Energy Corp.	Federal 29-148-97-#1
6207	NWNE	27-153-95	McK	Prosper Energy Corp.	Haugen #1
6243	SENW	26-137-92	Sta	Energetics Inc.	Martin - Kilzer #1
6251	SWSW	6-145-97	Dunn	Gulf Oil Corp.	Blackburn #1-6-4D
6289	NESW	10-155-91	Moun	Thomson Petroleum Inc.	Harstad et al. #1
6296	NESW	9-163-87	Ren	Shell Oil Co.	Larson #23X-9
6310	SENW	6-144-101	Bil	Supron Energy Corp.	Federal 6-144-101 #1
6362	C SW	18-155-95	Wil	Amerada Hess Corp.	Marvin Iverson #23-1
6368	SESE	24-149-96	McK	Hanson Oil Corp.	CCOC Federal #1-24
6378	SENE	30-143-100	Bil	Tenneco Oil Co.	Johnson #1-30
6388	NWNE	35-155-96	Wil	Amerada Hess Corp.	Capa Deep Unit #31-35
6401	NESW	10-163-87	Ren	Shell Oil Co.	Wisdahl #23-10
6413	NWSE	21-133-92	Het	Energetics Inc.	Harsch - Mehrer #44-21
6414	NENW	8-148-104	McK	Shell Oil Co.	U.S. Government #21-8
6429	SWSE	26-162-103	Div	W. H. Hunt Trust Estate	Sakbo #1
6447	SWNW	8-139-97	Sta	Anadarko Prod. Co.	Kostelecky #1
6466	SWNE	3-163-87	Ren	Shell Oil Co.	Mott #32X-3
6472	NESW	16-144-98	Bil	Gulf Oil Corp.	State #2-16-4B
6489	NENE	30-144-96	Dun	Amoco Prod. Co.	Roy Karey #1
6504	SWNE	1-162-87	Ren	Stone Oil Co.	Ones #1
6530	SENE	18-141-95	Dunn	Amoco Prod. Co.	Wolberg #1
6535	NENE	2-161-83	Bot	Shell Oil Co.	Greek #41-2
6541	SENE	13-162-100	Div	Tipperary Oil & Gas Corp.	Olsen #1
6545	SESW	28-159-95	Wil	W. H. Hunt Trust Estage	Haug #1
6551	NENW	23-141-101	Bil	Jerry Chambers Oil Producer	Franks Creek State #1-23
6562	NENW	23-144-105	Gol	Tenneco Oil Co.	Rose Gasho #1-23
6582	NESW	8-148-95	Dunn	Al-Aquitaine Oil & Gas Co.	Deep Creek #1
6591	NWNW	35-143-94	Dunn	Amoco Prod. Co.	Odin Anderson #1
6607	NENE	5-161-94	Burk	North Central Oil Corp.	Priebe State #1
6616	NENW	26-153-101	McK	Mosbacher - Pruet Oil Co.	FLB #1-26
6667	NENW	36-143-98	Bil	Mosbacher - Pruet Oil Co.	State Gresz #1-36-1B
6673	NESW	30-160-102	Div	W. H. Hunt Trust Estate	Nelson #1
6677	NESE	14-157-90	Moun	True Oil Co.	Halverson #33-14
6683	NWSW	13-143-90	Mer	True Oil Co.	Hauck #13-13

Well No.	QQ	S-T-R	County	Operator	Well Name
6684	NENW	2-161-85	Ren	Shell Oil Co.	Osterberg #21-2
6687	SWNE	16-154-95	Wil	Amerada Hess Corp.	State "E" #32-16
6702	NWSW	30-157-101	Wil	Union Texas Petroleum	Melvin Anderson #1
6705	SWSE	25-161-103	Div	Mosbacher - Pruet	George C. Anderson #1
6723	NESW	2-157-96	Wil	Apache Corp. - Williams Explor. Co.	Williams - Delaney #1-2
6744	NENW	22-142-99	Bil	W. H. Hunt Trust Estate	Hlebechuk - FLB #1
6745	SESW	10-159-97	Wil	Hunt Energy Corp.	Halvorson - FLB #1
6751	NWNW	3-161-101	Div	Patrick Petroleum Corp.	Johnson #1
6764	NENW	2-155-90	Moun	Donald C. Slawson	Kvamme #2-1
6776	SWNE	23-149-104	McK	Shell Oil Co.	USA #32-23-21
6780	SENE	24-151-89	Moun	Bass Enterpr. Prod. Co.	Robert Andes #24-1
6797	SESW	16-139-92	Sta	W. H. Hunt Trust Estate	Rummel State #1
6798	NESE	16-162-96	Div	Shell Oil Co.	Rindel #43-16
6802	SWNW	24-160-93	Burk	Brownlie, Armstrong, Wallace, & Bander	Western Investment Co. #24-12
6806	NWNE	8-155-101	Wil	Tenneco Oil Co.	Booke #1-8
6826	NENW	19-149-97	McK	Samedan Oil Corp.	Kelly #1
6828	NENE	8-145-94	Dunn	Amoco Prod. Co.	Merrill Unit #1
6839	NESE	11-150-104	McK	Shell Oil Co.	USA #43-11
6872	NESE	16-153-88	Moun	Marathon Oil Co.	Mae Olson
6886	SWSE	3-141-96	Dunn	Amoco Prod. Co.	Sadowsky "B" #1
6887	SWNE	35-146-95	Dunn	Amoco Prod. Co.	Richardson #1
6896	NESE	22-157-100	Wil	W. H. Hunt Trust Estate	NJOS #1
6904	SENW	3-147-104	McK	Brownlie, Armstrong, Wallace, & Bander	Federal #3-32
6915	SWSW	26-156-95	Wil	Kissinger Petroleum Corp.	Olson #13-26
6947	SENW	18-144-103	Gol	Terra Resources, Inc.	Mosser #1-18
6995	NWSE	36-142-101	Bil	Getty Oil Co.	Mystery Creed "A" #36-10
7004	NESE	30-155-100	Wil	Lamar Hunt	Treffery #1
7007	SESE	26-138-98	Sta	Supron Energy Corp.	Privratsky #1
7008	NWNW	11-151-97	McK	Supron Energy Corp.	Rolfsrud #1
7011	SWNE	10-142-100	Bil	W. H. Hunt Trust Estate	Gregory #1
7020	SENE	5-137-88	Gra	Texas Pacific Oil Co.	William Steckler #1
7054	NENW	14-156-102	Wil	Patrick Petroleum Co.	Fedje #1
7063	SWNW	22-157-97	Wil	Hunt Energy Corp.	Johnson #1

Well No.	QQ	S-T-R	County	Operator	Well Name
7073	NWNW	10-153-95	McK	Texaco Inc.	Silurian Unit 10 #1
7116	NESW	24-160-99	Div	Terra Resources, Inc.	Federal #1-24
7127	NWNE	30-139-96	Sta	Shell Oil Co.	Kostelecky #31-30
7142	SENE	1-151-102	McK	Al-Aquitaine, Inc.	Green #1-1
7164	NWSE	10-158-101	Wil	W. H. Hunt Trust Estate	Hanson #1
7214	SESE	33-149-92	Dunn	Exxon Corp.	Bull Family #1
7218	NWSW	17-145-103	McK	Terra Resources, Inc.	BNRR #1-17
7226	NENW	10-149-99	McK	Amoco Prod. Co.	Sondrol #1
7231	SESW	22-134-93	Het	Diamond Shamrock Corp.	Blicendorf #24-22
7238	NENE	5-154-88	Moun	Union Oil Co. of California	Oynes #1-B5
7247	NESW	5-140-95	Sta	Hunt Energy Corp.	Barta #1
7264	NWNE	27-147-101	McK	Pennzoil & Depco	BN #27-31
7306	SESE	35-149-102	McK	SunBehm Gas, Inc.	Okland #1
7340	NWSE	26-140-88	Mort	Amoco Prod. Co.	Richter #1
7348	SWSW	2-143-99	Bil	Amoco Prod. Co.	Hecker #1
7366	NENW	6-151-94	McK	Tenneco Oil Co.	Olive Wells #1-6
7384	NWNW	23-142-98	Bil	Crystal Oil Co.	Kuntz #11-23
7405	SWNE	8-155-99	Wil	Al-Aquitaine Exploration Ltd.	Brown #1-8
7420	SESW	4-146-96	Dunn	Amoco Prod. Co.	Bang #1
7422	NWSW	3-150-103	McK	Shell Oil Co.	Shaide #13-3
7426	SWSW	6-144-97	Dunn	Gulf Oil Corp.	Gary Houghton #1-61D
7433	SENE	36-159-95	Wil	Kissinger Petroleum Corp.	Carlson #8-36
7457	NWNE	20-150-92	Moun	Apache Corp.	Grace #1-20
7460	SWNW	4-144-93	Dunn	Terra Resources, Inc.	Nordsven #1-4
7469	NENW	30-145-93	Dunn	Amoco Prod. Co.	Dinkins #1
7470	NESE	1-153-99	Wil	Northwest Exploration Co.	Long Creek #2
7501	NESE	25-145-100	McK	Amoco Prod. Co.	Federal "B" #1
7503	SESE	36-153-104	Wil	Gulf Oil Corp.	Marley State #1-36-3C
7508	NWNW	2-140-100	Bil	Conoco Inc.	Federal Saddle #2
7512	SENE	22-146-101	McK	Kerr McGee Corp.	Federal #1-22
7531	SWNW	12-149-97	McK	Wm. C. Kirkwood	Federal #12-12
7570	NENE	9-155-94	Moun	Kissinger Petroleum Corp.	Grondale #1-9
7577	SWNW	15-160-96	Ren	Shell Oil Co.	Dewing #12-15
7579	SENE	24-145-104	McK	Shell Oil Co.	USA #42-24A
7580	NWNW	4-148-102	McK	SunBehm Gas, Inc.	Haugen Coates #1
7584	NENW	8-145-95	Dunn	Amoco Prod. Co.	Roshau #1

Well No.	QQ	S-T-R	County	Operator	Well Name
7585	NENE	17-146-102	McK	Pennzoil Co. & Depco	French Creek #17-41 BN
7591	NENW	9-142-102	Bil	Diamond Shamrock Corp.	Rauch Shapiro #21-9
7611	NENW	21-146-99	McK	Pennzoil Co.	Grassy Butte #21-21
7612	SESW	15-155-87	Ward	Marathon Oil Co.	Berg #15-24
7616	SWNW	29-144-90	Mer	Conoco Inc.	Entze 29-1
7629	NWSE	25-144-101	Bil	Koch Exploration Co.	Federal #15-25
7650	NESW	31-150-102	McK	Teneco Oil Co.	Federal #1-31
7660	SWSW	24-163-97	Div	Patrick Petroleum Corp.	Vaaler #1-24
7685	SWSW	34-147-99	McK	Pennzoil Co.	Slawson #34-12 MC
7691	SENW	19-138-85	Mort	Amoco Prod. Co.	Olin #1
7704	NESE	23-150-98	McK	Gulf Oil Corp.	Shafer State #1-23-3B
7717	SESE	34-161-87	Ren	Shell Oil Co.	Golden #44X-34
7741	SWSW	28-156-94	Moun	Kissinger Petroleum	Ortloff #13-28
7743	NWSE	3-150-97	McK	Al-Aquitaine Exploration, Ltd.	Kennedy #1-3
7745	NENE	10-147-92	Dunn	Santa Fe Energy Co.	Young Bear #1
7746	SWSW	17-145-102	McK	Pennzoil Co. & Depco	Cinnamon Creek #17-14 B
7760	SESW	24-146-93	Dunn	Mosbacher - Pruet Oil Co.	Thomas Cook #24-1
7763	NWSW	6-150-100	McK	Al-Aquitaine Exploration, Ltd.	6-150-100 Sanders #1-6
7773	SESE	6-163-94	Burk	Shell Oil Co.	Joos #44-6
7781	NESE	16-155-100	Wil	Lamar Hunt	Rolfstad State #2
7783	SENW	1-150-90	McL	Home Petroleum Corp.	Tribal #1-1
7789	NWSW	2-157-97	Wil	Petr. Lewis Corp.	Flaten #23-2X
7797	SESE	14-137-87	Mort	Texas Pacific Oil Co.	Bachler #1
7812	NENE	18-146-103	McK	Shell Oil Co.	USA #41-18-96
7818	NESE	5-140-89	Mort	Amoco Prod. Co.	Wehri #1
7845	SENW	23-150-101	McK	Petroleum Inc. & Excel	Nygaard State #1
7850	NESW	27-147-102	McK	Pennzoil Co. & Depco	Bridger Creek #27-23 BN
7879	C NE	22-149-100	McK	Champlin Petroleum Co.	State - Rogness 41-22 #1
7887	SWNE	17-142-100	Bil	Tenneco Oil Co.	Mee USA #3-17
7918	SESW	29-154-89	Moun	Marathon Oil Co.	Kulland #29-24
7931	SESW	33-155-97	Wil	Mapco Inc.	NCGA #14-33
7978	NWSE	17-145-91	Dunn	Terra Resources, Inc.	Tozier #1-17
8012	NESW	32-163-84	Ren	Monsanto Co.	Gates #1
8013	SENE	1-145-100	McK	Amoco Prod. Co.	Storm #1
8020	SWNE	34-150-99	McK	Alpar Resources, Inc.	Rogness #1-34

Well No.	QQ	S-T-R	County	Operator	Well Name
8060	SWNE	7-148-89	McL	Apache Corp.	Solcum #1
8069	SESE	12-154-90	Moun	Marathon Oil Co.	Jensen #12-44
8071	NENW	3-152-90	Moun	Lear Petroleum Exploration, Inc.	Parshall S.D. #1
8075	NESE	8-142-101	Bil	Conoco, Inc.	Federal Hanson #8-1
8079	SESW	34-143-99	Bil	W. H. Hunt Trust Estate	Demaniow #1
8088	NWNE	28-141-93	Sta	Mobil Oil Corp.	William Bernhardt #1
8095	SWNW	17-149-93	Dunn	Shell Oil Co.	Packineau Bia #12-17
8098	SENE	9-139-99	Sta	Monsanto Co.	Forelich #1
8107	SWNE	23-147-96	Dunn	Amoco Prod. Co.	Engvold #1-A
8115	NESW	24-142-92	Dunn	Keldon Oil Co.	Dressler #1
8125	SESE	29-153-94	McK	Energetics, Inc.	Felland #44-29
8137	NENW	21-154-100	Wil	Samedan Oil Corp.	Pedorenko #1-21
8138	SENW	15-153-96	McK	Home Petroleum	Federal #15-1
8158	SWSE	6-138-82	Mort	Pennzoil Co.	Sweet Briar #6-34
8163	SWSW	36-151-96	McK	Kissinger Petroleum Corp.	State #13-36
8169	NENW	21-138-92	Sta	Gulf Oil Corp.	Leviathan #1-21-1B
8177	SESE	18-151-87	Ward	Marathon Oil Co.	Dobrinski #18-44
8180	NESW	1-158-100	Wil	Depco, Inc.	Johnson #23-1
8215	SESE	25-147-98	McK	Gulf Oil Corp.	Morman Butte #1-25-3C
8235	SESE	36-144-92	Dunn	Santa Fe Energy Co.	State #1-36
8239	SWNE	17-158-97	Wil	Lear Petroleum Exploration, Inc.	Oase #1
8287	NWSE	18-146-104	McK	Shell Oil Co.	USA #33-18-123
8307	NENW	31-155-77	McH	Asamera Oil (U.S.), Inc.	Larson #1
8314	SENE	8-147-103	McK	Shell Oil Co.	USA #43-8
8323	NWSE	23-155-81	Ward	Lomax Exploration Co.	Klein #1
8337	NESE	30-141-102	Bil	Patrick Petroleum Co.	Harris-Federal #1-30
8342	NWNW	36-140-95	Sta	Supron Energy Corp.	Lawrence #1
8371	SWSW	17-157-91	Moun	True Oil Co.	Kuster #14-17
8374	NENE	4-144-96	Dunn	Adobe Oil & Gas Corp.	Federal Killdeer $41-4
8394	SESE	14-146-93	Dunn	ANR Production Co.	FLB - Asker #1-14A
8395	SWSE	1-137-87	Mort	Sun Oil Co.	Jacob Larson #1
8413	SENW	14-156-97	Wil	Depco, Inc.	Wittrock #22-14
8423	SESW	9-154-102	Wil	Gulf Oil Corp.	Alfson #1-9-4C
8431	SWSW	21-145-96	Dunn	Amoco Prod. Co.	Sahaydak #1
8474	SESW	15-144-102	Bil	Tenneco Oil Co.	Graham USA #1-15

Well No.	QQ	S-T-R	County	Operator	Well Name
8487	SESE	13-143-102	Bil	Conoco, Inc.	Blacktail #13-1
8553	SENW	17-140-82	Mort	Shell Oil Co.	Vogel #22-27
8558	NWSE	29-144-99	Bil	Amoco Prod. Co.	A. W. Thompson "B" #1-A
8711	SESE	31-146-80	McL	Sun Oil Co.	Flemmer #1
8720	NENE	34-144-81	McL	Sun Oil Co.	Fahlgren #1
8803	NENE	22-151-80	McH	Atlantic Richfield Co.	Wunderlich #1
9351	NWSE	6-144-101	Bil	Supron Energy Corp.	Federal #3

APPENDIX B

APPENDIX B - Formation Tops

Well numbers are those of the North Dakota Geological Survey. Tops are given as feet below Kelly Bushing (KB). Dashes indicate that the particular unit was absent. Stratigraphic unit abbreviations are as follows: (B) Bakken Formation, (MM) Bakken middle member, (LS) Bakken lower shale, (TF) Three Forks Formation.

TABLE 3

FORMATION AND MEMBER TOPS USED IN THIS STUDY

Well No.	KB	B	MM	LS	TF
15	2037	6350	*	*	6370
21	2284	8973	8986	*	9000
32	2458	9618	9632	9685	9712
39	1480	4642	4660	*	4678
49	2100	6630	6340	*	6352
52	1839	6740	6750	6757	6765
61	1570	4820	*	*	4835
83	1627	3259	*	*	3268
105	2175	7542	7556	7569	7578
110	2205	4005	4012	*	4020
126	1772	6369	6382	6396	6401
133	2204	7595	*	*	7603
170	1669	3810	3818	*	3830
286	1539	3857	3883	3897	3910
328	1895	3693	*	*	3706
348	1603	3588	3596	*	3606
358	1502	4187	*	*	4197
359	2256	3722	3742	*	3756
392	1875	6960	6973	6985	6998
413	2145	10390	10411	10452	10468
432	1957	6375	6384	*	6390
457	1539	3888	3904	*	3928
527	2472	11197	11214	11254	11286
528	2271	8402	8419	8444	8465
568	1677	*	*	*	3180
569	1919	*	*	*	2906
579	1902	*	*	*	2752
588	2087	6791	6800	*	6813

Well No.	KB	B	MM	LS	TF
607	2149	10510	10523	10574	10600
656	1632	6032	6046	*	6052
659	2288	3558	*	*	3566
665	1792	4790	*	*	4808
685	2107	3590	*	*	3607
693	1984	5183	*	*	5195
763	1947	5092	*	*	5102
765	2027	*	*	*	5048
769	1481	4816	4830	4835	4842
772	2007	*	*	*	5455
780	1486	*	*	*	3272
793	2102	9994	10014	10046	10076
806	2180	3542	3566	*	3580
895	1683	3799	*	*	3804
917	1602	*	*	*	3060
955	2236	3901	3912	*	3922
981	2218	3433	3446	*	3469
999	2253	10930	10946	10988	11007
1069	1536	5242	5250	*	5266
1102	1664	3424	3430	*	3440
1202	2129	10267	10287	10331	10356
1354	1489	4361	*	*	4372
1385	2360	9748	9770	9828	9870
1405	2342	10737	10760	10794	10822
1620	2426	8602	8615	*	8624
1636	2401	9726	9742	9803	9836
1666	1675	3857	3272	*	3277
1673	2160	3750	3766	*	3779
1748	2198	10644	10370	10716	10752
1858	2468	10884	10908	10952	10974
1968	1513	4045	4066	4098	4118
2010	2195	7740	7763	7804	7826
2033	2389	9096	9111	9174	9209
2584	2463	10775	10784	*	10801
2615	3039	11670	11685	11718	11740
2618	2212	9778	9792	9826	9838
2675	1478	4692	4701	4735	4762
2746	21110	10994	11014	11058	11089
2800	1887	6461	6474	6500	6515
2820	2416	10569	10589	10630	10655
2828	2233	11050	11068	11114	11141
2887	2001	8933	8943	8988	9002
2967	2317	10226	10248	10288	10314
3007	2372	9403	9412	9476	9506
3044	2200	9621	9630	9657	9666
3154	1952	7020	7027	7080	7102
3167	2293	10180	10200	10244	10268
3268	2540	*	*	*	10203
3363	2332	10130	10144	10203	10227
3392	2317	9240	9249	9314	9343

Well No.	KB	B	MM	LS	TF
3492	2309	9608	9624	9658	9668
3515	2292	9414	9423	9431	9436
3686	2159	10603	10624	10674	10708
3827	1502	4171	4178	*	4184
3899	2409	9536	9548	9609	9634
3920	1605	*	*	*	3938
3978	2281	*	*	*	6454
4061	2020	10406	10425	10484	10520
4074	2136	8078	8089	8150	8180
4113	2198	10648	10666	10709	10737
4323	2460	9515	9530	9586	9612
9340	1972	9895	9916	9978	10015
4347	1532	3910	3935	3950	3957
4362	1508	4954	4960	*	4974
4389	2126	*	*	*	6036
4394	2157	8745	8758	8822	8851
4423	2248	8453	8465	8528	8552
4439	2200	10653	10665	10691	10697
4507	2214	7978	7990	8049	8072
4508	1975	7492	7502	7542	7565
4599	1957	7173	7184	7224	7244
4611	2435	11009	11024	11058	11076
4618	2413	10252	10266	10298	10310
4655	1486	4144	4152	4174	4185
4685	1865	5740	*	*	5758
4723	2048	10680	10693	10724	10731
4725	2373	11120	11136	11177	11200
4754	2223	10540	10552	10582	10590
4790	1517	5335	5343	5368	5381
4837	2112	8856	8867	8926	8944
4844	1511	4919	4923	*	4932
4846	1518	4473	4476	*	4494
4923	1573	5659	5679	*	5704
4924	1514	4834	4838	*	4848
4940	2252	7596	7606	*	7615
4957	2212	10459	10480	10520	10536
4958	1973	7570	7580	7623	7652
4984	2524	8340	*	*	8342
4990	1788	6576	6586	6596	6599
4992	1618	5761	5774	5806	5831
5071	1503	5218	5224	*	5239
5072	2367	9629	9644	9720	9767
5088	2409	10161	10177	10245	10292
5105	2120	8100	8116	8134	8146
5114	2192	9498	9508	9550	9560
5135	2291	8664	8674	8738	8762
5141	1598	3664	3675	3720	3752
5143	2688	*	*	*	9894
5147	1534	5222	5227	*	5246

Well No.	KB	B	MM	LS	TF
5158	2117	7520	7534	7546	7502
5182	2165	11282	11288	11317	11321
5184	1552	3871	*	*	3888
5197	2434	9644	9658	9716	9742
5248	2243	8986	8996	9054	9076
5255	2717	*	*	*	9547
5277	1543	3856	3863	*	3876
5279	1476	4199	*	*	4205
5280	1527	3774	3776	*	3785
5281	1470	3864	*	*	3875
5283	1477	4342	4348	*	4370
5315	2357	9724	9740	9790	9818
5333	2376	10086	10100	10164	10212
5379	1980	6541	*	*	6461
5404	2209	8048	8057	8116	8140
5410	1949	9664	9688	9738	9767
5496	2420	*	*	*	7767
5528	2313	9594	9608	9660	9685
5535	2299	8988	8999	9063	9092
5621	2583	10646	10656	10668	10673
5692	1587	5561	5569	*	5590
5762	2433	10422	10433	10466	10475
5783	2548	8691	*	*	8694
5831	2300	9805	9821	9896	9948
5908	1901	6645	6657	6699	6721
5919	2459	8853	8866	8937	8972
5989	1903	7346	7354	7439	7471
6021	1553	5160	5167	*	5184
6065	1976	9764	9784	9826	9850
6087	2325	9569	9587	9648	9687
6114	2390	10591	10608	10664	10687
6126	1499	4420	4426	*	4441
6182	2186	10656	10673	10712	10732
6186	2088	10774	10790	10832	10858
6207	2375	10284	10306	10352	10379
6243	2357	8529	*	*	8534
6251	2574	11035	11046	11076	11096
6289	2281	9508	9522	9558	9594
6296	1807	6020	6026	6044	6050
6310	2198	10440	10448	*	10460
6362	2305	9772	9792	9840	9867
6368	2499	10980	11000	11039	11065
6378	2612	10658	10667	*	10777
6388	2032	9560	9580	9630	9654
6401	1703	5858	5864	5880	5890
6413	2508	*	*	*	7925
6414	2334	10638	10647	*	10659
6429	2145	8194	8206	8262	8283
6447	2496	10025	10032	*	10040
6466	1734	5816	5822	5839	5847

Well No.	KB	B	MM	LS	TF
6472	2536	10950	10960	10980	10995
6489	2310	10687	10699	10725	10736
6504	1716	6042	6048	6064	6070
6530	2595	10371	10380	10393	10398
6535	1589	5237	5244	*	5254
6541	2349	8418	8429	8489	8514
6545	2348	9363	9375	9432	9462
6551	2320	10381	10388	*	10392
6562	2574	10531	*	*	10532
6582	2378	11009	10040	11031	11006
6591	2130	9963	9976	10000	10008
6607	2404	8566	8580	8648	8678
6616	2100	10605	10619	10654	10662
6667	2690	10959	10968	10988	10991
6673	2100	8872	8884	8938	8958
6677	2305	8700	8716	8745	8768
6683	2097	9129	9142	9168	9176
6684	1713	5814	5820	5832	5838
6687	2300	10001	10022	10075	10104
6702	2383	10298	10310	10352	10366
6705	2100	8436	8446	8504	8525
6723	2423	9900	9904	9967	9994
6744	2712	10957	10967	*	10988
6745	2317	9590	9602	9662	9686
6751	2244	8475	8484	8546	8572
6764	2220	8986	9006	9036	9062
6776	2330	10685	10696	10739	10741
6780	2133	9030	9049	9078	9100
6797	2494	9189	9198	*	9210
6798	2141	8101	8111	8180	8206
6802	2394	8862	8881	8930	8966
6806	2192	10507	10523	10566	10580
6826	2244	11051	11070	11111	11130
6828	2337	10648	10662	10696	10709
6839	2066	10520	10530	10550	10556
6872	2108	8677	8693	8723	8746
6886	2617	10554	10564	10579	10583
6887	2324	10715	10729	10764	10776
6896	2075	10107	10123	10166	10186
6904	2196	10460	10470	*	10492
6915	2411	10093	10112	10174	10216
6947	2531	10738	10742	*	10748
6995	2505	10429	10438	10401	10444
7004	1898	10454	10472	10514	10532
7007	2756	10087	*	*	10089
7008	2291	10796	10814	10860	10887
7011	2782	10833	10841	10850	10852
7020	2342	7952	*	*	7961
7054	2151	10207	10221	10264	10278

Well No.	KB	B	MM	LS	TF
7063	2339	10422	10438	10498	10520
7073	2323	10108	10130	10178	10206
7116	2236	9160	9174	9224	9245
7127	2521	9917	9930	*	9938
7142	2086	10659	10674	10705	10710
7164	2087	9550	9562	9610	9626
7214	2363	10498	10512	10560	10586
7218	2606	10792	10797	*	10808
7226	2167	10998	11014	11049	11058
7231	2367	7685	11264	11276	11303
7238	2132	8541	8558	8585	8600
7247	2455	10086	10097	10111	10115
7264	2029	10542	10552	10582	10586
7306	2402	10945	10956	10980	10985
7340	2230	8116	8122	*	8127
7348	2722	11120	11127	11150	11154
7366	2175	10486	10503	10549	10573
7384	2648	10843	10852	*	10871
7405	2116	10690	10707	10756	10780
7420	2754	11381	11396	11432	11456
7422	2127	10631	10641	10672	10678
7426	2508	10979	10989	11018	11030
7433	2324	8285	9297	9360	9391
7457	2143	10363	10380	10424	10454
7460	2240	10230	10243	10276	10287
7469	2170	10323	10337	10372	10384
7470	2342	11184	11201	11242	11266
7501	2556	10959	10968	11000	11001
7503	2183	10536	10550	10575	10590
7508	2767	10874	10890	*	10896
7512	2616	11017	11036	*	11053
7531	2191	10731	10751	10795	10820
7570	2074	10092	10114	10188	10240
7577	1842	6513	6520	6536	6540
7579	2664	10852	10857	*	10864
7580	2433	10949	10959	10983	10989
7584	2322	10775	10790	10826	10840
7585	2391	10759	10767	10787	10788
7591	2536	10521	*	*	10524
7611	2628	11209	11220	11247	11266
7612	2219	8099	8110	8138	8152
7616	2219	9306	9320	9352	9358
7629	2633	10835	10844	*	10858
7650	2262	10795	10804	10830	10836
7660	1944	7648	7658	7724	7748
7685	2581	11064	11276	11303	11307
7691	2094	7089	*	*	7102
7704	2022	10880	10900	10942	10965
7717	1903	6785	6792	6815	6825
7741	2331	10247	10268	10334	10382

Well No.	KB	B	MM	LS	TF
7743	2244	10753	10771	10814	10840
7745	2048	10054	10072	10115	10136
7746	2432	10729	10735	*	10744
7760	2318	10390	10407	10449	10463
7763	2244	10912	10923	10955	10962
7773	1922	7365	7377	7440	7466
7781	1950	10460	10478	10519	10539
7783	2212	9563	9579	9610	9636
7789	2253	10346	10364	10410	10432
7797	2281	7463	*	*	7470
7812	2478	10702	10709	*	10716
7818	2284	8666	8674	8681	8683
7845	2318	10959	10971	10999	11003
7850	2222	10668	10676	10701	10704
7879	2209	10929	10941	10971	10975
7887	2741	10791	10801	10808	10810
7918	2169	9097	9114	9142	9174
7931	2124	10716	10735	10782	10809
7978	2223	9854	9868	9900	9911
8012	1642	5373	5379	*	5384
8013	2442	10968	10980	11007	11012
8020	2114	10948	10964	10999	11011
8060	2109	9372	9386	9411	9430
8069	2213	9157	9174	9207	9236
8071	1967	9135	9153	9195	9224
8075	2430	10423	10430	*	10433
8079	2747	11047	11056	*	11080
8088	2165	9450	9459	9471	9474
8095	2330	10803	10819	10861	10836
8098	2611	10407	10416	*	10421
8107	2538	11112	11129	11166	11189
8115	2277	9517	9526	9546	9551
8125	2175	10442	10462	10510	10538
8137	2024	10646	10663	10707	10725
8138	2072	10000	10019	10067	10093
8158	1792	5996	*	*	6016
8163	2457	10784	10801	10841	10864
8169	2372	8834	*	*	8841
8177	2167	8622	8639	8660	8674
8180	2133	9646	9662	9712	9732
8215	2512	11073	11086	11107	11129
8235	2258	9702	9714	9740	9745
8239	2298	9962	9976	10032	10057
8287	2450	10613	10619	*	10627
8307	1516	4685	*	*	4710
8314	2221	10589	10598	10622	10623
8323	1587	5716	5726	*	5736
8337	2603	*	*	*	10283
8342	2418	9793	9802	9816	9818

Well No.	KB	B	MM	LS	TF
8371	2310	9296	9313	9343	9370
8384	2435	10898	10913	10944	10957
8394	2417	10516	10533	10575	10588
8395	2211	7440	*	*	7446
8413	2255	10162	10180	10235	10259
8423	2155	10559	10573	10605	10614
8431	2573	11156	11170	11199	11217
8474	2173	10366	10374	10378	10379
8487	2344	10420	10428	*	10438
8553	1994	6413	*	*	6432
8558	2675	11069	11078	11103	11105
8711	1900	6211	*	*	6226
8720	1815	6064	*	*	6072
8803	*	6000	*	*	6022
9351	2203	10463	10472	10482	10483

APPENDIX C

APPENDIX C - Bakken Core Descriptions

Well numbers are those of the North Dakota Geological Survey. The depths used are those marked on the core samples, usually at the well site, and these may not correspond directly to depths taken from well logs.

Well No.

105. Stanolind Oil Co. - Waswick No. 1, CSW¼ sec. 2, T. 153 N., R. 95 W., Ward County.

7552-59	Shale, black (N1), fissile, hard, pyritic, noncalcareous, abundant condonts, planar laminations accented by pyrite.
7559-61	Dolomite, very silty, brownish gray (5YR 4/1) to medium gray (N5), slightly pyritic, abundant brachiopods in upper part, possible trough cross lamination at 7560.5.
7561-64	Siltstone, dolomitic, calcareous in part, dark greenish gray (5GY 4/1) to medium light gray (N6), slightly pyritic, cross laminated in part, planar laminations, low angle planar cross bedding at 7563, abundant brachiopods.

527. California Oil Co. - Rough Creek Unit No. 1, NW¼NE¼ sec. 13, T. 148 N., R. 98 W., McKenzie County.

11225-28	Sandstone, very fine sand, well sorted, subangular to subrounded, medium dark gray (N4) to olive gray (5Y 4/1), faintly laminated, pyritic.
11228-36	Siltstone, calcareous, medium dark gray (N4) to brownish gray (5YR 4/1), irregularly laminated, bidirectional (herringbone) cross lamination, pyritic, lack of fossils, some bioturbation in upper part.
11236-62	Siltstone, as above, several thin beds of limestone, whole brachiopods and bioturbation in lower part.
11262-88	Shale, black (N1), grayish black (N2) to dark gray (N3) from 11274-83, hard, fissile, pyritic, noncalcareous, tasmanites, conodonts, fish scales (?); numerous thin, nearly vertical, calcite-filled fractures.

11288-91 Limestone, grayish black (N2) to medium dark gray (N4), silty, abundant whole brachiopods at top.

1202. Amerada Petroleum Corp. - Jens Strand No. 1, SE¼NW¼ sec. 6, T. 152 N., R. 94 W., McKenzie County.

10257-77 Shale, black (N1), fissile, hard siliceous, noncalcareous, pyritic, planar laminations; fractured throughout by straight, thin, vertical calcite-filled fractures, numerous open fractures also; fish scales (?), conodonts.

10277-92 Sandstone, medium dark gray (N4), very pyritic at top, calcareous, very fine to fine sand, well sorted, quartzose, subrounded to subangular, cross laminated in part, irregular planar laminations.

10292-321 Siltstone, nearly very fine sand in part, medium dark gray (N4) to brownish gray (5YR 4/1), irregular laminations, calcareous, slightly pyritic, abundant whole brachiopods and bioturbation in lower half.

10321-43 Shale, black (N1), as above, fractured throughout, vertical fracture faces lined with calcite, abundant fish scales (?) at 10321.

2618. Pan American Petroleum Corp. - Jacob Huber No. 1, SW¼SE¼ sec. 15, T. 145 N., R. 91 W., Dunn County.

9794-807 Siltstone, interbedded with thin limestones, medium dark gray (N4) to dark greenish gray (5GY 4/1), abundant small brachiopods, slightly pyritic, planar laminations, cross laminated at 9799, soft-sediment deformation structures, irregularly interbedded with dark gray shale (N3) from 9802-9808.

9807-09 Limestone, medium gray (N5), brachiopods, planar laminations.

9809-28 Siltstone, as above, whole brachiopods, bioturbated in part, a few distinct burrows.

9828-37 Shale, black (N1), hard fissile, siliceous, noncalcareous, pyritic, abundant conodonts, tasmanites at 9835, planar laminations, contact with middle member is even and slightly gradational.

4340. Pan American Petroleum Corp. - Clifford Marmon No. 1, SW¼SW¼ sec. 2, T. 154 N., R. 95 W., Williams County.

9885-9906 Shale, black (N1), fissile, hard, siliceous, noncalcareous, pyritic, contact with overlying Lodgepole Formation is even and abrupt, abundant conodonts and tasmanities, planar laminations, fractured throughout, some

fractures are straight and calcite-filled.

9906-10 Limestone, very silty, dolomitic, olive gray (5Y 4/1), whole brachiopods, no apparent bedding, pyrite replacing some skeletal material.

9910-15 Siltstone, calcareous, light olive gray (5Y 6/1) to medium dark gray (N4), shaly in part, irregular laminations, some low angle cross laminations, bioturbated in part, few brachiopods, lack of fossils in lower 3 feet.

9915-26 Limestone, sandy, oolitic in part, medium gray (N5); interbedded with sandstone, calcareous, very fine to fine sand, well sorted, light olive gray (5Y 5/2), ripple cross laminations and low angle planar cross bedding, lack of fossils.

9926-67 Siltstone, as above, planar laminations in upper half, few brachiopods, abundant bioturbation and whole brachiopods in lower half, cross laminated locally.

9967-10011 Shale, black (N1), as above, fractured throughout, a few open fractures, contact with overlying middle member is slightly irregular.

4508. Northern Pump Co. - Louis Peterson No. 1, NW¼NE¼ sec. 7, T. 161 N., R. 90 W., Burke County.

7501-03 Shale, black (N1), fissile, hard, siliceous, pyritic, planar laminations, conodonts, slightly gradational contact with the underlying middle member.

7503-07 Dolomite, very silty, greenish gray (5GY 6/1), pyritic, brachiopods, possible pelmatozoan fragments, bidirectional (herringbone) cross bedding at 7505.

7507-44 Siltstone, medium gray (N5), very dolomitic in upper part, nearly of very fine sand size, wavy and irregular laminations, burrows, pelmatozoan fragments, abundant brachiopods from 7536-44, contact with lower shale is even and slightly gradational.

7544-51 Shale, black (N1), as above, abundant conodonts and tasmanites.

5088. Shell Oil Co. - Shell-Texel No. 21-35, NE¼NW¼ sec. 35, T. 156 N., R. 93 W., Mountrail County.

10158-69 Shale, black (N1), fissile, hard, pyritic, noncalcareous, contact with the overlying Lodgepole Formation is even and abrupt, abundant conodonts, fish scales (?) at 10158, planar laminations.

10169-82 Siltstone, olive gray (5Y 4/1) to medium gray (N6), shaly, abundant brachiopods; apparent large scale, low angle, planar cross bedding in upper part; some small scale trough cross bedding, soft-sediment deformation structures, becoming coarse silt to fine sand at base.

10182-90 Limestone, very sandy, medium gray (N5) to brownish gray (5YR 4/1), massive; interbedded with sandstone, very calcareous, fine to medium sand, quartzose, well rounded, well sorted, brownish gray (5YR 4/1).

10190-208 Siltstone, calcareous, medium light gray (N6) to brownish gray (5YR 4/1), planar laminations, isolated small scale trough cross bedding, lack of fossils.

10208-40 Siltstone, as above, abundant bioturbation and whole brachiopods.

10240-90 Shale, black (N1), as above, abundant tasmanites, fish scales (?) at 10241 and 10288, scattered conodonts, planar laminations, contact with the underlying Three Forks Formation is slightly gradational with some interbedding of the Bakken shale and the green shale of the Three Forks.

7579. Shell Oil Co. - USA No. 42-24A, SE¼NE¼ sec. 24, T. 145 N., R. 104 W., McKenzie County.

10856-60 Shale, black (N1), hard, fissile, siliceous, pyritic, noncalcareous, faint planar laminations, contact with the overlying Lodgepole Formation is planar and slightly gradational.

10860-67 Siltstone, very dolomitic, brownish gray (5YR 4/1) to greenish gray (5GY 6/1), possible bioturbation, pyritic, sandy at base, contact with underlying Three Forks Formation is irregular.

7887. Tenneco Oil Co. - Mee USA No. 3-17, SW¼NE¼ sec. 17, T. 142 N., R. 100 W., Billings County.

10786-94 Shale, black (N1), fissile, hard, pyritic, noncalcareous, conodonts, tasmanites, fish scales (?); numerous straight, nearly vertical, calcite-filled fractures and fracture faces; planar to slightly irregular laminae.

10794-800 Limestone, microcrystalline, silty, dolomitic, medium dark gray (N4) to dark gray (N3), abundant brachiopods and pelmatozoan fragments; small scale, trough cross bedding at 10798; planar laminations; large, open, vertical fracture at 10799; contact with the upper shale member is slightly gradational.

10800-01 Shale, black (N1), as above, conodonts and tasmanites.

8177. Marathon Oil Co. - Dobrinski No. 18-44, SE¼SE¼ sec. 18, T. 151 N., R. 87 W., Ward County.

8630-39 Shale, black (N1), fissile, hard, pyritic, non-calcareous, siliceous, planar laminations, abundant conodonts, tasmanites, large terrestrial plant fragment at 8635.5, contact with the underlying middle member is very planar and abrupt, small fractures filled with calcite and pyrite.

8639-49 Siltstone, calcareous, locally dolomitic, medium light gray (N6) to medium dark gray (N4), pyritic at top, brachiopods, pelmatozoan fragments, soft-sediment deformation features, possible low angle, small scale, cross bedding at 8640, bioturbated from 8647-49.

8649-52 Limestone, slightly dolomitic, peloidal, brownish gray (5YR 4/1) to medium light gray (N6).

8652-62 Siltstone, as above, very calcareous, shaly, brachiopods, pelmatozoan fragments, planar laminations, disrupted laminations.

8662-67 Shale, black (N1), as above, pyrite lenses, planar laminations, abundant conodonts at 8662, tasmanites.

APPENDIX D

APPENDIX D - Type and Location of Geochemical Samples

Sample numbers correspond to NDGS well numbers. Depths used are those marked on the samples (cores or bags of cuttings) and may not correspond directly to depths attained from well logs. Under the member sampled column, U stands for upper shale, and L stands for lower shale. Locations are given by section, township, range, and county. In North Dakota all townships are north and all ranges are west.

TABLE 4

TYPE AND LOCATION OF GEOCHEMICAL SAMPLES

Sample No.	Depth	Sample Type	Member Sampled	Location	County
105	7562-68	Core	U	2-153-85	Ward
126	6370-90	Cuttings	U	33-156-83	Ward
286A	3855-77	Cuttings	U	32-164-78	Bottineau
286B	3900-10	Cuttings	L	32-164-78	Bottineau
392	6960-90	Cuttings	U	21-157-85	Ward
413A	10391-410	Core	U	5-147-93	Dunn
413B	10452-68	Core	L	5-147-93	Dunn
457	3890-904	Cuttings	U	34-164-78	Bottineau
527A	11205-20	Cuttings	U	13-148-98	McKenzie
527B	11262-86	Core	L	13-148-98	McKenzie
528A	8405-15	Cuttings	U	25-157-89	Mountrail
528B	8445-55	Cuttings	L	25-157-89	Mountrail
607	10508-21	Core	U	24-149-93	Dunn
793A	9993-10024	Core	U	22-149-91	Dunn
793B	10051-82	Core	L	22-149-91	Dunn
999	10994-11010	Core	L	23-154-100	Williams
1202A	10257-77	Core	U	6-152-94	McKenzie
1202B	10321-43	Core	L	6-152-94	McKenzie
1405	10796-813	Core	L	27-150-96	McKenzie
1748	10720-53	Core	L	6-152-94	McKenzie
1748Ls	10740-43	Core	L	6-152-94	McKenzie
1858	10963-69	Core	L	25-150-96	McKenzie
2033A	9090-110	Cuttings	U	30-160-94	Burke
2033B	9190-230	Cuttings	L	30-160-94	Burke
2618	9828-37	Core	L	15-145-91	Dunn
2675	4692-762	Cuttings	U&L	34-159-79	McHenry
2675A	4690-705	Cuttings	U	34-159-79	McHenry

Sample No.	Depth	Sample Type	Member Sampled	Location	County
267B	4730-60	Cuttings	L	34-159-79	McHenry
2820	10633-50	Core	L	5-161-95	McKenzie
2967	10285-303	Core	L	15-152-96	McKenzie
3007	9409-13	Core	U	30-159-95	Williams
3044	9620-70	Cuttings	U&L	27-143-92	Dunn
3167	10242-64	Core	L	31-153-95	McKenzie
3363	10213-23	Core	L	19-157-96	Williams
3492A	9608-24	Cuttings	U	25-146-90	Mercer
3492B	9658-68	Cuttings	L	25-146-90	Mercer
4113	10725-38	Core	L	4-150-93	Mountrail
4340A	9885-906	Core	U	2-154-95	Williams
4340B	9967-10008	Core	L	2-154-95	Williams
4507	7970-8080	Cuttings	U&L	21-163-101	Divide
4508A	7501-03	Core	U	7-161-90	Burke
4508B	7543-46	Core	L	7-161-90	Burke
4611	11010-76	Cuttings	U&L	36-146-96	Dunn
4723	10680-730	Cuttings	U&L	23-151-101	McKenzie
4790A	5335-45	Cuttings	U	20-159-91	Bottineau
4790B	5370-80	Cuttings	L	20-159-91	Bottineau
4837	8850-8940	Cuttings	U&L	12-160-100	Divide
4958	7557-80	Core	L	2-161-91	Burke
4990	6576-86	Cuttings	U&L	22-156-84	Ward
4992	5840-50	Cuttings	L	2-156-82	Ward
5072A	9625-40	Cuttings	U	22-158-94	Mountrail
5072B	9720-65	Cuttings	L	22-158-94	Mountrail
5088A	10155-69	Core	U	35-156-93	Mountrail
5088B	10240-86	Core	L	35-165-93	Mountrail
5831A	9800-30	Cuttings	U	23-157-94	Mountrail
5831B	9918-40	Cuttings	L	23-157-94	Mountrail
5908	6640-720	Cuttings	U&L	33-164-90	Burke
5989	7360-470	Cuttings	U&L	31-164-95	Divide
6401	5850-60	Cuttings	U	10-163-87	Renville
6466	5815-20	Cuttings	U	3-163-87	Renville
6489	10725-35	Cuttings	L	30-144-96	Dunn
6607A	8560-80	Cuttings	U	5-161-94	Burke
6607B	8640-70	Cuttings	L	5-161-94	Burke
6673A	8870-90	Cuttings	U	30-160-102	Divide
6673B	8930-50	Cuttings	L	30-160-102	Divide
6780	9030-100	Cuttings	U&L	24-151-89	Mountrail
6797	9180-90	Cuttings	U	16-139-92	Stark
6798A	8100-30	Cuttings	U	16-162-96	Divide
6978B	8180-200	Cuttings	L	16-162-96	Divide
6887	10710-30	Cuttings	U	35-146-95	Dunn
6896	10107-86	Cuttings	U&L	22-157-100	Williams
7004	10450-530	Cuttings	U&L	30-155-100	Williams
7008	10796-887	Cuttings	U&L	11-151-97	McKenzie
7164	9550-626	Cuttings	U&L	10-158-101	Williams
7579	10856-60	Core	U	14-145-104	McKenzie
7612	8110-50	Cuttings	U&L	15-155-87	Ward

Sample No.	Depth	Sample Type	Member Sampled	Location	County
7887A	10786-94	Core	U	17-142-100	Billings
7887B	10800-01	Core	L	17-142-100	Billings
8177A	8629-39	Core	U	18-151-87	Ward
8177B	8633-67	Core	L	18-151-87	Ward
8474	10363-72	Core	U	15-144-102	Billings
8711	6210-20	Cuttings	U	31-146-80	McLean
9351	10463-73	Core	U	6-144-101	Billings

APPENDIX E

APPENDIX E - Results of Thin Layer Chromatography

Samples are listed in order of increasing depth. The following abbreviations have been used; (EPOC) extract as a percent of organic carbon, (HC) ppm of hydrocarbons in rock as determined by thin layer chromatography, (HC/OC) ratio of hydrocarbons to organic carbon in milligrams per gram, (%HC in TE) hydrocarbons as a percent of total extract by thin layer chromatography, (HC/nonHC) ratio of hydrocarbons to nonhydrocarbons by thin layer chromatography, (Sat/OC) ratio of saturated hydrocarbons to organic carbon in milligrams per gram, (Aro/OC) ratio of aromatic hydrocarbons to organic carbon in milligrams per gram. Columns 7, 8, and 9 give the percent of saturated hydrocarbons, aromatic hydrocarbons, and resins and asphaltenes respectively, of the total extract. All of the above hydrocarbon parameters pertain to $C_{15}+$ hydrocarbons as determined from thin layer chromatography. Asterisks designate samples believed to be affected by contamination by nonindigenous oily substances.

TABLE 5

RESULTS OF THIN LAYER CHROMATOGRAPHY

	Sample No.	Depth	Wt. percent Organic Carbon	Bitumen (ppm)	EPOC	HC (ppm)	Saturates (%)	Aromatics (%)	Resins and Asphaltnes (%)	HC/OC (mg/gm)	% in HC in TE	HC/nonHC	Sat/OC (mg/gm)	Aro/OC (mg/gm)
	457	3890	5.25	3309	6.30	366	5.94	5.13	88.93	7.0	11.07	0.12	3.7	3.2
	2675	4629	15.40	11786	7.65	1905	4.66	11.51	83.83	12.4	16.17	0.19	3.6	8.8
	4790A	5335	5.36	5779	10.78	1078	11.20	7.45	81.35	20.1	18.65	0.23	11.9	8.1
	4790B	5882	11.65	5882	5.05	782	4.50	8.80	86.71	6.7	13.29	0.15	2.3	4.4
	6466	5816	10.71	3810	3.56	875	10.19	12.78	77.03	8.2	22.97	0.30	3.6	4.6
	8711	6210	5.50	2996	5.45	1003	10.85	22.61	66.54	18.2	33.46	0.50	5.9	12.3
	126	6370	4.25	7047	16.58	977	10.75	3.12	86.13	23.0	13.87	0.16	17.8	5.2
	4990	6576	11.30	7733	6.84	1248	6.77	9.36	83.86	11.0	16.14	0.19	4.6	6.4
	4508A	7501	14.4	11650	8.09	4669	9.80	30.54	59.66	32.6	40.34	0.68	7.9	24.7
	4508B	7543	13.6	8940	6.57	3534	9.22	30.32	60.47	26.0	39.54	0.65	6.1	19.9
	105	7550	15.6	12280	7.87	2905	6.63	17.03	76.34	18.6	23.66	0.31		5.2
	4958	7577	17.79	11075	6.23	3940	9.16	26.41	64.43	22.1	35.57	0.55	5.7	16.4
	4507	7970	11.86	12184	10.27	3616	12.20	17.48	70.32	30.5	29.68	0.42	12.5	18.1
*	6607A	8560	12.10	13377	11.06	5642	29.01	29.01	57.83	46.6	42.18	0.73	14.6	32.1
	8177A	8629	15.00	12050	8.03	4286	9.95	25.62	64.44	28.6	35.57	0.55	8.0	30.6
*	6607B	8640	6.89	8962	6.89	5739	18.19	45.85	35.96	44.1	64.04	1.78	12.5	31.6
	8177B	8663	7.07	3850	5.46	1081	6.26	21.74	72.01	15.3	28.00	0.17	3.4	11.8
	4837	8850	13.00	8460	6.51	3234	13.21	25.02	61.78	24.9	38.23	0.62	8.6	16.3

Sample No.	Depth	Wt. percent Organic Carbon	Bitumen (ppm)	EPOC	HC (ppm)	Saturates (%)	Aromatics (%)	Resins and Asphaltenes (%)	HC/OC (mg/gm)	% HC in TE	HC/nonHC	Sat/OC (mg/gm)	Aro/OC (mg/gm)
6780	9030	14.90	12633	8.48	3788	9.70	20.28	70.02	25.4	29.98	0.43	8.2	17.2
3007	9409	11.80	5690	4.82	2740	14.08	34.08	51.84	23.2	48.16	0.93	6.8	16.4
7164	9550	12.60	15400	12.22	3366	8.15	13.70	78.15	26.7	21.85	0.28	10.0	16.9
3492A	9608	10.50	8433	8.03	3513	15.82	25.84	58.34	33.5	41.66	0.71	12.7	20.8
3492B	9658	16.30	12717	7.80	5601	13.81	30.24	55.96	34.4	44.05	0.79	10.7	23.6
2618	9828	15.10	12870	8.52	4665	11.26	24.99	63.75	30.9	36.25	0.57	9.6	21.3
4340A	9885	11.95	5770	4.83	2963	22.79	28.57	48.64	24.8	51.36	1.06	11.0	13.8
4340B	9967	10.97	5080	5.54	3518	25.79	32.08	42.14	32.1	57.87	1.37	14.3	17.8
793A	9993	12.46	11965	9.60	3769	10.49	21.01	68.50	30.2	31.50	0.46	10.1	20.2
793B	10051	17.07	13310	7.80	3780	10.31	18.08	71.60	22.2	28.40	0.40	8.0	14.1
6896	10107	12.90	13250	10.27	4280	10.58	21.72	67.70	33.2	32.30	0.48	10.9	22.3
5088A	10155	13.50	9470	7.01	3324	9.64	25.47	64.90	24.6	35.11	0.54	6.7	17.9
5088B	10240	11.00	12910	11.74	5151	14.57	25.33	60.10	46.8	39.90	0.66	17.1	29.7
3363	10213	10.90	2280	2.09	1496	30.84	34.79	34.38	13.7	65.62	1.91	6.5	7.3
3167	10242	11.10	2120	1.91	1504	40.44	30.51	29.04	13.6	70.96	1.00	7.7	5.8
1202A	10257	10.58	6040	5.71	1953	16.58	15.74	67.67	18.5	32.33	0.48	9.5	9.0
2967	10285	9.97	6280	6.30	3949	33.42	29.47	37.12	39.6	62.88	1.69	21.1	18.6
1212A	10321	13.44	8739	6.50	2294	12.36	13.90	73.75	17.1	26.25	0.36	8.0	9.0
8474	10362	10.30	6330	6.15	3232	20.03	31.03	48.94	31.4	51.06	1.04	12.3	19.1
413A	10391	10.38	9128	8.79	2312	14.05	11.28	74.68	22.3	25.33	0.34	12.4	10.0
413B	10450	7.48	7030	9.40	2277	19.01	13.39	67.61	30.4	32.40	0.48	17.9	12.6
9351	10463	10.10	4098	4.06	2549	28.76	33.45	37.80	25.2	62.21	1.65	11.7	13.6
607	10508	12.39	9420	7.60	3426	12.10	24.26	63.63	27.6	36.37	0.57	9.2	18.4
2820	10633	11.00	6770	6.15	3519	25.22	26.76	48.03	32.0	51.98	1.08	15.7	16.5
4723	10700	7.94	4993	6.29	2142	21.89	21.01	57.11	27.0	42.90	0.75	13.8	13.2
6887	10710	8.89	3448	3.88	962	12.99	14.91	72.11	10.8	27.90	0.39	5.0	5.8
1748	10720	10.85	4100	3.78	2392	28.40	29.93	41.67	22.0	58.33	1.40	10.7	11.3
1748Ls	10740	0.87	1000	11.49	658	46.11	19.72	34.18	75.7	65.82	1.93	53.0	

Sample No.	Depth	Wt. percent Organic Carbon	Bitumen (ppm)	EPOC	HC (ppm)	Saturates (%)	Aromatics (%)	Resins and Asphaltnes (%)	HC/OC (mg/mg)	% in HC in TE	HC/nonHC	Sat/OC (mg/gm)	Aro/OC (mg/gm)
4113	10725	11.00	8020	7.29	3363	13.50	32.18	54.33	33.3	45.67	0.84	9.8	23.5
7887A	10786	7.76	3350	4.32	2222	44.33	33.66	28.6	66.34	1.97	1.97	19.1	9.5
1405	10796	13.23	4250	3.21	2221	23.24	29.02	47.74	16.8	52.26	1.09	7.5	9.3
7008	10796	9.34	4814	5.15	3018	41.50	21.20	37.30	32.3	62.70	1.68	21.4	10.9
7887A	10800	10.14	3840	3.79	2608	47.19	20.73	32.09	25.7	67.92	2.12	17.9	7.9
7579	10856	13.70	14060	10.26	4266	8.30	21.75	69.95	30.8	30.05	0.43	8.5	22.3
1858	10963	13.09	6739	5.15	2891	19.43	23.46	57.11	22.1	42.89	0.75	10.0	12.1
999	10994	12.44	4904	3.94	2681	18.83	35.84	45.33	21.6	54.67	1.21	7.4	14.1
4611	11010	8.60	6501	7.56	3165	29.07	19.62	51.32	36.8	48.69	0.95	37.2	14.8
527A	11205	7.33	5417	7.39	2952	43.02	11.48	45.51	40.3	54.50	1.20	31.8	8.5
527B	11262	7.62	6880	9.03	3885	43.76	12.71	43.53	51.0	56.47	1.30	39.5	11.5

APPENDIX F

APPENDIX F - Results of Pyrolysis

Samples are listed in order of increasing depth. S_1 and S_2 values are given in milligram hydrocarbons per gram of rock, and S_3 values are given as milligrams CO_2 per gram rock. $T^{o}C$ designates the temperature in degrees centigrade attained at the highest point of the S_2 peak. Ratios of S_1 and S_2 to organic carbon are given in milligrams hydrocarbons per gram organic carbon. The machine used was a ROCK-EVAL 1, manufactured by Girdel. The analytical conditions used are the standard ones as outlined by IFP-FINA. Initial temperature of the oven during analysis was $250^{o}C$, and temperature was increased at $25^{o}C$ per minute up to $550^{o}C$. Helium was passed over the sample as a carrier gas for pyrolytic products.

TABLE 6

RESULTS OF PYROLYSIS

Sample No.	Depth	Wt. Percent Organic Carbon	S_1	S_2	S_3	T°C	S_1+S_2	Prod. Index	S_1/OC	S_2/OC
286A	3855	9.39	2.04	46.00	3.78	414	48.03	.042	22	490
286B	3900	7.32	0.47	16.72	1.69	407	17.79	.027	6	228
2675A	4690	12.01	2.00	53.18	4.03	417	55.18	.036	17	443
2675B	4730	15.10	2.14	48.15	4.61	411	50.28	.043	14	319
4992	5840	11.11	3.20	47.78	2.28	412	50.98	.063	29	430
6401	5850	17.55	4.66	72.89	2.82	417	77.54	.060	27	417
8711	6210	10.82	3.34	63.78	1.17	407	67.12	.050	31	589
392	6860	17.13	1.63	22.82	1.00	419	24.45	.067	10	133
5989	7360	12.99	6.35	60.49	1.20	430	66.84	.095	49	466
4508B	7543	13.50	5.28	61.54	0.68	423	66.82	.079	39	456
105	7550	15.60	4.22	85.57	2.24	450	89.79	.047	27	549
4958	7557	15.17	7.24	88.40	0.82	428	95.64	.076	48	482
6798A	8100	6.99	3.35	30.94	2.03	435	34.30	.098	48	442
7612	8110	14.17	7.32	92.46	2.34	420	99.78	.073	52	652
6798B	8180	9.88	3.54	34.03	1.98	434	37.57	.094	36	344
528A	8405	15.48	4.73	69.40	3.73	421	74.13	.064	31	448
528B	8445	10.79	3.47	52.26	2.30	421	55.73	.062	32	484
6607A	8560	12.87	3.52	48.94	1.76	437	52.46	.067	27	380
8177A	8629	15.00	6.55	100.79	2.34	418	107.34	.061	44	672
6607B	8640	11.78	5.06	46.63	1.26	439	51.69	.098	43	395
8177B	8663	7.10	1.59	27.69	0.74	420	29.28	.054	22	397
6673A	8870	15.17	5.45	77.60	1.84	4.33	83.05	.065	36	512
6673B	8930	10.15	4.00	49.75	1.90	431	53.75	.074	19	490

Sample No.	Depth	Wt. Percent Organic Carbon	S_1	S_2	S_3	T°C	S_1+S_2	Prod. Index	S_1/OC	S_2/OC
2033A	9090	8.39	7.10	37.40	2.07	436	44.50	.159	85	466
6797A	9180	10.15	2.74	54.10	1.54	417	56.84	.048	27	533
2033B	9190	9.91	6.06	23.48	1.36	439	29.54	.205	61	237
3007	9409	13.41	4.90	34.95	0.89	443	39.84	.123	37	261
3044	9620	11.02	1.92	34.42	3.89	419	36.34	.053	17	312
3492	9620	14.68	7.88	83.30	2.13	424	91.18	.086	54	567
5072A	9625	10.61	1.80	23.11	2.25	437	24.91	.072	17	218
5072B	9720	9.71	4.49	23.15	1.72	437	27.64	.162	46	238
5831A	9800	11.69	4.18	24.49	2.03	438	28.67	.145	36	209
2618	9828	15.10	7.12	86.32	1.21	421	93.44	.076	47	572
4340A	9885	10.70	4.78	19.17	1.11	446	23.95	.199	45	179
5831B	9918	10.01	4.55	15.89	2.01	441	20.43	.222	46	238
4340B	9967	11.01	4.50	14.65	1.36	439	19.15	.234	41	151
793A	9993	14.52	8.72	82.81	1.55	431	91.53	.095	60	570
793B	10051	14.74	8.62	80.27	1.53	429	88.89	.096	58	545
5088A	10155	13.50	5.27	54.74	0.76	440	60.01	.088	48	405
3363	10213	10.90	4.47	15.93	0.68	445	20.40	.219	41	146
5088B	10240	11.00	5.74	44.24	0.67	437	49.98	.115	52	402
3167	10242	11.10	5.84	12.34	0.85	448	18.18	.321	53	111
1202A	10257	9.71	4.36	15.53	1.70	440	19.90	.219	45	160
2967	10285	9.97	5.87	10.70	1.58	452	16.57	.354	59	107
1202B	10321	11.82	5.27	16.82	1.32	446	22.09	.239	45	142
413B	10455	12.91	6.54	49.09	1.00	438	55.64	.118	51	380
4113	10725	11.00	4.56	35.51	0.83	431	40.07	.114	41	323
7887A	10786	8.01	4.23	8.61	0.90	453	12.84	.329	53	108
6489	10796	11.48	5.95	17.37	0.69	445	23.31	.255	52	154
7887B	10800	9.26	5.09	9.10	1.12	450	14.19	.359	55	98
7579	10856	13.70	3.58	59.07	1.50	440	62.65	.057	26	26
1858	10963	10.99	5.60	15.94	1.01	440	21.54	.260	51	145
999	10994	11.38	5.22	22.67	0.95	436	27.89	.187	46	199
4611	11010	6.86	6.88	20.85	1.18	437	27.72	.248	100	304
527B	11262	7.62	4.93	7.04	0.76	446	11.97	.412	65	92

APPENDIX G

APPENDIX G - Results of Visual Kerogen Typing

Samples are arranged in numerical order. CF stands for confidence factor (F=fair, P=poor).

TABLE 7

Results of Visual Kerogen Typing

Sample No.	% Amorphous	% Herbaceous	% Woody	% Coaly	CF
105	95	0	0	0	P
126	85	10	5	0	F
413A	95	5	0	0	F
413B	90	10	0	0	F
527A	80	0	10	20	P
527B	80	0	0	20	P
607	80	10	0	10	F
793A	80	20	0	0	P
793B	80	20	0	0	P
999	85	5	0	10	F
1202A	90	10	0	0	F
1202B	80	10	0	10	F
1405	80	10	0	10	F
1748	85	5	0	10	F
2618	90	5	0	5	P
2675	90	0	0	10	P
2820	80	5	5	10	P
2967	90	0	5	5	P
3007	90	0	10	0	P
3167	90	5	0	5	?
3363	80	10	0	10	?
4340A	80	10	0	10	P
4340B	70	20	0	10	F
4507	80	20	0	0	F
4508	90	0	0	10	P
4723	90	0	0	10	F
4790A	90	10	0	0	F
4790B	80	0	0	20	P
4837	90	0	0	10	?
4958	90	0	0	10	F
4990	95	00	0	5	P
5088A	80	10	0	10	P

Sample No.	% Amorphous	% Herbaceous	% Woody	% Coaly	CF
5088B	80	15	5	0	P
6466	90	10	0	0	F
6780	95	5	0	0	?
6896	90	0	0	10	P
7004	90	0	0	10	P
7008	80	0	0	20	P
7164	90	0	0	10	P
7579	90	0	0	10	P
7887	90	0	0	10	F
8177A	80	10	0	10	P

APPENDIX H

APPENDIX H - Results of Vitrinite Reflectance

TABLE 8

RESULTS OF VITRINITE REFLECTANCE

Sample No.	Depth	Mean refl. value	Std. dev.
4507	7970	0.44	0.17
4723	10700	0.66	0.13
1858	10963	0.77	0.17
999	10994	0.73	0.17
1748	10720	0.80	0.18
1405	10796	0.87	0.20
1202A	10257	0.80	0.18
1202B	10321	0.72	0.19

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REFERENCES CITED

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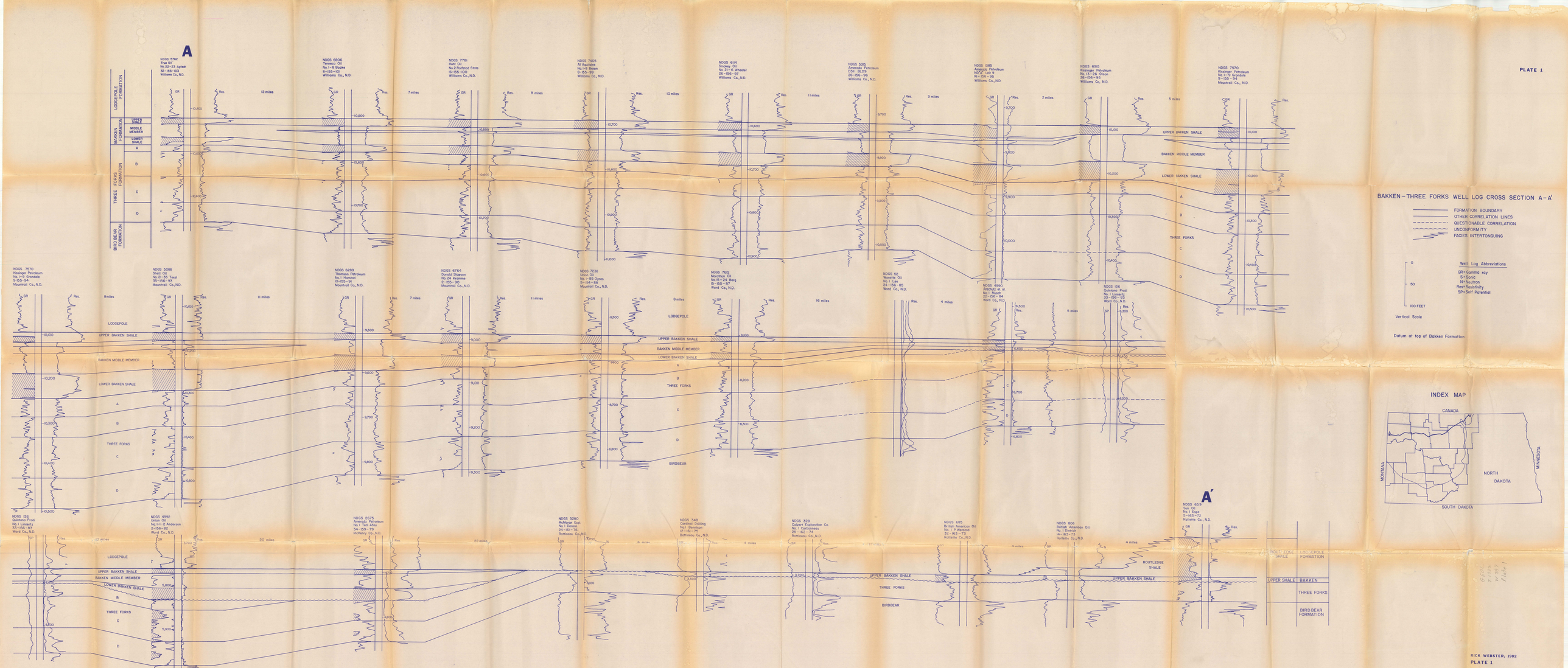

A
NDGS 5762
True Oil
No.22-23 Agtelt
32-156-103
Williams Co.,N.D.
NDGS 6806
Tenneco Oil
No.1-9 Bryke
8-155-101
Williams Co., N.D.
NDGS 7781
Hunt Oil
No.2 Rolfstad State
16-155-100
Williams Co.,N.D.
NDGS 7405
Ml Aquitaine
No.1-9 Brown
9-155-99
Williams Co., N.D.
NDGS 6614
Smokey Oil
No. 21-6 Wheeler
26-156-97
Williams Co.,N.D.
NDGS 5345
Amerada Petroleum
DSH BLD'9
26-156-96
Williams Co., N.D.
NDGS 1385
Amerada Petroleum
NCR* Unit 9
16-156-95
Williams Co., N.D.
NDGS 6965
Kissinger Petroleum
No.13-26 Olson
26-156-95
Williams Co., N.D.
NDGS 7570
Kissinger Petroleum
No.1-9 Grandale
9-155-94
Mountrail Co., N.D.
LODGEPOLE FORMATION
BAKKEN FORMATION
UPPER SHALE
MIDDLE MEMBER
LOWER SHALE
THREE FORKS FORMATION
A
B
C
D
BIRD BEAR FORMATION
UPPER BAKKEN SHALE
BAKKEN MIDDLE MEMBER
LOWER BAKKEN SHALE
THREE FORKS
NDGS 7570
Kissinger Petroleum
No.1-9 Grandale
9-155-94
Mountrail Co.,N.D.
NDGS 5088
Shell Oil
No. 31-25 Texel
35-156-93
Mountrail Co.,N.D.
NDGS 6289
Thomson Petroleum
No.1 Harstad
10-155-91
Mountrail Co.,N.D.
NDGS 6764
Donald Slawson
No.24 Kreamer
2-155-90
Mountrail Co.,N.D.
NDGS 7238
Union Oil
No.1-85 Dynes
5-154-88
Mountrail Co.,N.D.
NDGS 7612
Marathon Oil
No.15-24 Berg
15-155-87
Ward Co., N.D.
NDGS 52
Wanetta Oil
No.1-Lund
34-156-85
Ward Co., N.D.
NDGS 4990
Enschutz et al
No.1 Musch
22-156-84
Ward Co., N.D.
NDGS 126
Quintana Prod.
No.1 Lillehei
33-156-83
Ward Co.,N.D.
NDGS 126
Quintana Prod.
No.1 Lillehei
33-156-83
Ward Co.,N.D.
NDGS 4992
Union Oil
No.11-2 Anderson
2-156-82
Ward Co., N.D.
NDGS 2675
Amerada Petroleum
No.1 Ted Afsu
34-159-79
Mallery Co.,N.D.
NDGS 5280
McMoran Expl.
No.1 Dennis
24-161-76
Bottineau Co.,N.D.
NDGS 349
Cardinal Drilling
No.1 Bennison
12-161-75
Bottineau Co.,N.D.
NDGS 328
Calvert Exploration Co.
No.1 Carbonneau
Portage 24-161-74
Bottineau Co.,N.D.
NDGS 685
British American Oil
No.1 P Wenstad
32-163-73
Rollette Co.,N.D.
NDGS 806
British American Oil
No.1 Dietrich
14-163-73
Rollette Co.,N.D.
NDGS 659
Sun Oil
No.1 Espe
5-163-72
Rollette Co., N.D.
A'
ROUTLEDGE SHALE
LODGEPOLE FORMATION
UPPER SHALE
BAKKEN
THREE FORKS
BIRD BEAR FORMATION
PLATE 1
BAKKEN-THREE FORKS WELL LOG CROSS SECTION A-A'
FORMATION BOUNDARY
OTHER CORRELATION LINES
QUESTIONABLE CORRELATION
UNCONFORMITY
FACIES INTERTONGUING
0
50
100 FEET
Vertical Scale
Well Log Abbreviations
GR=Gamma ray
S=Sonic
N=Neutron
Res=Resistivity
SP=Self Potential
Datum at top of Bakken Formation
INDEX MAP
CANADA
MONTANA
NORTH DAKOTA
MINNESOTA
SOUTH DAKOTA
RICK WEBSTER, 1982
PLATE 1

B

NDGS 7760
Mosbacher – Pruet
#24-1 Thomas-Cook
24-146-93
Dunn Co., N.D.

11.5 miles

NDGS 2618
Pan American
#1 Huber
15-145-91
Dunn Co., N.D.

10 miles

NDGS 7616
Conoco
#29-1 Entze
29-144-90
Mercer Co., N.D.

6 miles

NDGS 6683
True Oil
#13-13 Mosick
13-143-90
Mercer Co., N.D.

8.5 miles

NDGS 21
Kelly – Plymouth
#1 Fritz Leutz
28-142-89
Mercer Co., N.D.

7.5 miles

NDGS 7818
Amoco Prod.
#1 Mehri
5-140-89
Morton Co., N.D.

10.5 miles

NDGS 7340
Amoco Prod.
#1 Richter
26-140-188
Morton Co., N.D.

17 miles

NDGS 7691
Amoco Prod.
#1 Olin
19-138-85
Morton Co., N.D.

17 miles

NDGS 3978
Austral Oil
Lalgang Unit 6524 #1
34-137-83
Morton Co., N.D.

B´

LODGEPOLE FORMATION

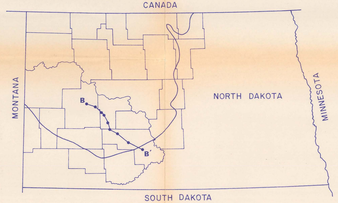
BAKKEN FORMATION: UPPER SHALE; SILTSTONE MEMBER; LOWER SHALE

THREE FORKS FORMATION: A; B; C; D

BIRDBEAR FORMATION

UPPER BAKKEN SHALE
BAKKEN SILTSTONE
LOWER BAKKEN SHALE
THREE FORKS
BIRDBEAR

INDEX MAP



BAKKEN - THREE FORKS WELL LOG CROSS SECTION B-B´

Formation boundary
Other correlations
Questionable correlation
Unconformity

Datum at top of Bakken Formation

0
50
100 feet
Vertical Scale

Well Log Abbreviations
GR = Gamma ray
LL_D = Laterolog deep
S = Sonic
N = Neutron
Res. = Resistivity

GEOL.
T1982
W397
Plate 2

RICK WEBSTER, 1982

PLATE 2

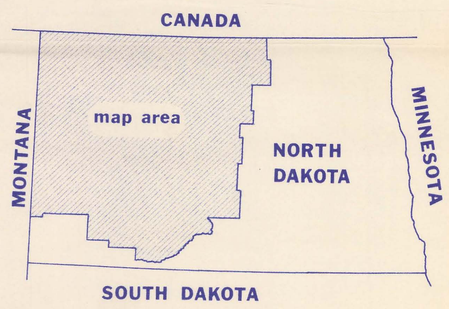
PLATE 3

INDEX MAP OF CONTROL WELLS AND GEOCHEMICAL SAMPLES

- well log control point and NDGS well number
- geochemical sample from cuttings
- geochemical sample from core
- county boundary

DIVIDE
BURKE
BOTTINEAU
ROLETTE
RENVILLE
PIERCE
WILLIAMS
MOUNTRAIL
WARD
McKENZIE
McHENRY
McLEAN
SHERIDAN
MERCER
DUNN
OLIVER
STARK
GOLDEN VALLEY
BILLINGS
MORTON
BURLEIGH
HETTINGER
GRANT

limit lower shale
limit middle member
limit upper shale



10 0 10 20 30 40 miles

SCALE: 1 / 500,000

GEOL-
T 1982
W 397
Plate 3

RICK WEBSTER, 1982

PLATE 3